GE
Energy Management

PJM Renewable Integration Study (PRIS)

Final Project Review

Revision 07

Stakeholder Meeting of
March 3, 2014

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Meeting Agenda

Time	Topic	Discussion Leader	Minutes
9:30 – 9:45	Introduction and Project Overview	PJM + GE	15
9:45 – 10:30	Key Findings & Recommendations	GE	45
10:30 – 10:45	Task 1: Wind, Solar, and Load Profile Development	GE/AWST	15
10:45 – 11:00	Break		15
11:00 – 11:15	Task 2: Scenario Development & Analysis	GE	15
11:15 – 11:30	Task 3a: Hourly GE MAPS Analysis	GE	15
11:30 – 11:45	Task 3a: Renewable Capacity Valuation	GE	15
11:45 – 12:00	Task 3a: Transmission Overlays Analysis	PowerGEM	15
12:00 – 1:00	Lunch		60
1:00 – 1:15	Task 3a: Statistical & Reserve Analysis	EnerNex	15
1:15 – 1:30	Task 3a: Challenging Days/Sub-Hourly PROBE Analysis	EnerNex/PowerGEM	15
1:30 – 1:45	Task 3a: Power Plant Cycling Cost Analysis	Intertek	15
1:45 – 2:00	Task 3a: Power Plant Cycling Emissions Analysis	Intertek	15
2:00 – 2:15	Task 3b: Market Analysis: Regulation Requirements	EnerNex	15
2:15 – 2:30	Break		15
2:30 – 2:45	Task 3b: Market Analysis: Uncertainty in Market	PowerGEM/GE	15
2:45 – 3:00	Task 3b: Market Analysis: Preferred Practices	Exeter Associates/GE	15
3:00 – 3:15	Task 4: Mitigation. Facilitation, Reporting	GE	15
3:15 – 3:30	Discussion of Key Findings & Recommendations	PJM + GE + Partners	15

Project Introduction and Overview (PJM + GE) [15 Minutes]

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Project Team

PJM
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EnerNex
Tom Mousseau
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PowerGEM
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Scott Gass
Boris Gisin
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Jim Mitsche

Study Objective

- Perform a comprehensive renewable power integration study to:
  - Determine, for the PJM balancing area, the operational, planning, and energy market effects of large-scale integration of wind power as well as mitigation/facilitation measures available to PJM.
  - Make recommendations for the implementation of such mitigation/facilitation measures.

- This study was initiated at the request of PJM stakeholders.

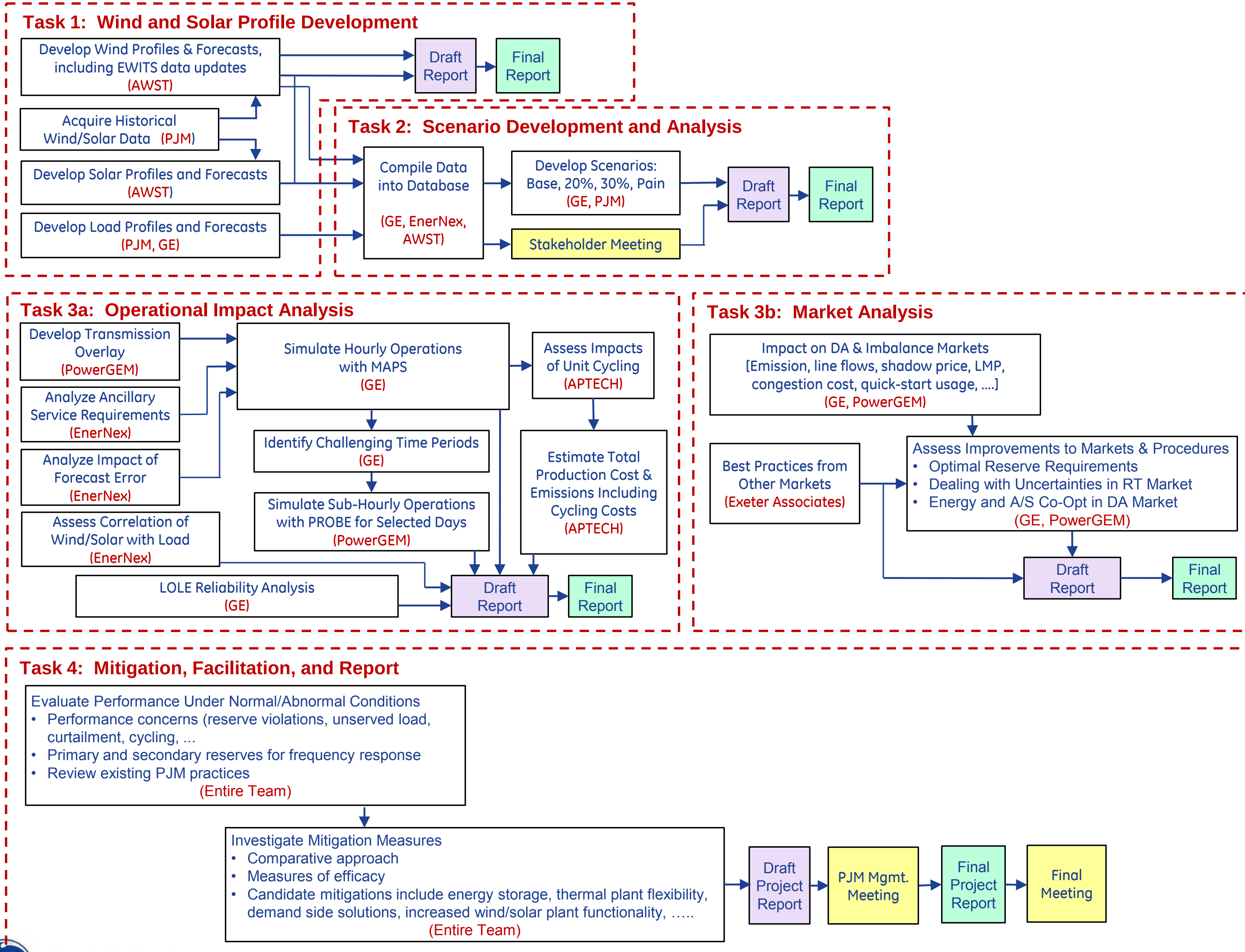
- Data Sources:
  - This study used a combination of publicly available and confidential data to model the Eastern Interconnection, the PJM grid, and its power plants

Perspective and Scope Limitations . . .

- The purpose of the study is to assess impacts to the grid if additional wind and solar is connected.
  - This study is not an analysis of the economics of those resources, therefore quantifying the capital investment required to construct additional wind and solar is beyond the scope of this study.
  - This study looks at a broad range of operational, planning, and market impact issues of large-scale wind/solar integration in a future year (i.e., 2026), hence, this study was not meant to be a detailed near-term planning study for any specific issue or mitigation.
  - This study should not be viewed as a long-term transmission planning study, or as an IRP study.
  - The capacity value of renewables was investigated, but it did not cover possible secondary impacts to the capacity market such as increased retirements due to non-economic performance or a possible need for generators to recover more in the capacity market because of reduced revenue in the energy market.

Analytical Approach & Tools

- GE MAPS based Hourly Production Simulation (PJM + Rest of EI)
- Year of the Study: 2026
- Transmission Overlay Analysis
- PROBE based Sub-Hourly Simulation of Interesting Days
- GE MARS based Renewable Capacity Valuation
- Statistical Analysis of Load and Renewable Data
- Reserve Analysis
- Power Plant Cycling Cost Analysis
- Power Plant Cycling Emissions Analysis


Task 1: Wind and Solar Profile Development
Develop Wind Profiles & Forecasts, including EWITS data updates (AWST)
Acquire Historical Wind/Solar Data (PJM)
Develop Solar Profiles and Forecasts (AWST)
Develop Load Profiles and Forecasts (PJM, GE)
Draft Report
Final Report
Task 2: Scenario Development and Analysis
Compile Data into Database (GE, EnerNex, AWST)
Develop Scenarios: Base, 20%, 30%, Pain (GE, PJM)
Stakeholder Meeting
Draft Report
Final Report
Task 3a: Operational Impact Analysis
Develop Transmission Overlay (PowerGEM)
Analyze Ancillary Service Requirements (EnerNex)
Analyze Impact of Forecast Error (EnerNex)
Assess Correlation of Wind/Solar with Load (EnerNex)
Simulate Hourly Operations with MAPS (GE)
Identify Challenging Time Periods (GE)
Simulate Sub-Hourly Operations with PROBE for Selected Days (PowerGEM)
Assess Impacts of Unit Cycling (APTECH)
Estimate Total Production Cost & Emissions Including Cycling Costs (APTECH)
LOLE Reliability Analysis (GE)
Draft Report
Final Report
Task 3b: Market Analysis
Impact on DA & Imbalance Markets [Emission, line flows, shadow price, LMP, congestion cost, quick-start usage, ….] (GE, PowerGEM)
Best Practices from Other Markets (Exeter Associates)
Assess Improvements to Markets & Procedures
• Optimal Reserve Requirements
• Dealing with Uncertainties in RT Market
• Energy and A/S Co-Opt in DA Market
(GE, PowerGEM)
Draft Report
Final Report
Task 4: Mitigation, Facilitation, and Report
Evaluate Performance Under Normal/Abnormal Conditions
• Performance concerns (reserve violations, unserved load, curtailment, cycling, …
• Primary and secondary reserves for frequency response
• Review existing PJM practices
(Entire Team)
Investigate Mitigation Measures
• Comparative approach
• Measures of efficacy
• Candidate mitigations include energy storage, thermal plant flexibility, demand side solutions, increased wind/solar plant functionality, …..
(Entire Team)
Draft Project Report
PJM Mgmt. Meeting
Final Project Report
Final Meeting

Key Findings & Recommendations (GE) [45 Minutes]

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Study Scenarios

Scenario	Renewable Penetration in PJM	Wind/Solar (GWh)	Wind + Solar Siting	Comments
2% BAU	Reference	Existing wind + solar	Existing Plants (Business as Usual)	Benchmark Case for Comparing Scenarios
14% RPS	Base Case 14%	109 / 11	Per PJM Queue & RPS Mandates	Siting based on PJM generation queue and existing state mandates
20% LOBO	20%	150 / 29	Low Offshore + Best Onshore	Onshore wind selected as best sites within all of PJM
20% LODO	20%	150 / 29	Low Offshore + Dispersed Onshore	Onshore wind selected as best sites by state or region
20% HOBO	20%	150 / 29	High Offshore + Best Onshore	High offshore wind with best onshore wind
20% HSBO	20%	121 / 58	High Solar + Best Onshore	High solar with best onshore wind
30% LOBO	30%	228 / 48	Low Offshore + Best Onshore	Onshore wind selected as best sites within all of PJM
30% LODO	30%	228 / 48	Low Offshore + Dispersed Onshore	Onshore wind selected as best sites by state or region
30% HOBO	30%	228 / 48	High Offshore + Best Onshore	High offshore wind with best onshore wind
30% HSBO	30%	179 / 97	High Solar + Best Onshore	High solar with best onshore wind

Key Findings

Scenario	Renewable Energy Delivered (GWh)	Production Cost ($B)	Wholesale Load Payments Delta ($B)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Gas Displacement (%)	Coal Displacement (%)	Reduced Imports (%)
2% BAU	17,217	40.5	71.8	192,025	421,618	47,390	0%	0%	0%
	Delta Relative to 2% BAU Scenario								
14% RPS	105,642	-6.8	-4.2	-49,590	-32,866	-21,397	-47%	-31%	-20%
20% HOBO	157,552	-10.6	-21.5	-90,194	-34,604	-31,302	-57%	-22%	-20%
20% LOBO	160,490	-9.9	-10.1	-56,854	-66,940	-32,267	-35%	-42%	-20%
20% LODO	161,542	-10.1	-8.6	-58,322	-59,647	-41,085	-36%	-37%	-25%
20% HSBO	164,253	-12.1	-12.7	-66,682	-42,505	-53,696	-41%	-26%	-33%
30% HOBO	256,400	-16.1	-21.5	-118,876	-58,453	-77,631	-46%	-23%	-30%
30% LOBO	259,428	-14.8	-10.1	-68,192	-170,920	-19,134	-26%	-66%	-7%
30% LODO	259,345	-15.1	-8.6	-68,013	-119,526	-68,653	-26%	-46%	-26%
30% HSBO	253,918	-15.6	-15.3	-84,511	-88,847	-78,382	-33%	-35%	-31%
Average							-39%	-36%	-24%

- Production Cost is sum of Fuel Costs, Variable O&M Costs, Any Emission Tax/Allowance Cost, and Start-Up Costs, adjusted for Import Purchases and Export Sales.
- Gas and Coal Delta are reduction in gas based and coal based generation relative to the 2% BAU scenario. Gas and Coal Displacements are relative to the Total Renewable Energy Delivered, e.g., Coal Displacement = Coal Delta / Total Renewable Energy Delivered.
- High coal displacement in 30% LOBO is due to cumulative impact of high wind and remaining local congestion in western PJM.
- The transmission system would handle all resulting power transfers, since ALL tie-line transmission limits were modeled.

Key Findings: PJM's Readiness

- The study findings in general support the notion that PJM system, with adequate transmission and ancillary services in the form of Regulation, will not have any significant issue absorbing the higher levels of renewable energy penetration considered in the study.
  - In performing this project, the GE Team has come to the conclusion that PJM's current energy scheduling practices already incorporates recommendations from previous renewable energy integration studies.
  - "Adequate Transmission" refers to the additional transmission overlay added to the system to keep the congestion down to a target level, as described in the under the Transmission Overlay task.
  - "Adequate Regulation" refers to the additional regulation required to mitigate the wind and solar variability, as described in the Reserve Analysis Task. It was determined that no additional primary (synchronized or non-synchronized) or secondary reserve were needed.
  - Note that dynamic simulations to evaluate potential voltage and frequency control issues were not within the scope of this study.

Key Findings: General Impacts

- Principal impacts of higher penetration of renewable energy into the grid:
  - No insurmountable operating issues after many simulated scenarios of system-wide hourly operation, supported by hundreds of hours of sub-hourly operation using actual PJM ramping capability.
  - Lower system-wide Production Costs
    - Production Costs = variable system costs (fuel, VOM, and emission tax / allowance costs), and start-up costs, adjusted for import purchases and export sales.
  - Lower Coal and CCGT generation under all scenarios
    - On average, 36% of the delivered renewable energy displaced PJM coal fired generation, 39% displaced PJM gas fired generation, and the rest displaced PJM imports (or increased exports).
  - Lower emissions of criteria pollutants and greenhouse gases
  - No unserved load and minimal renewable energy curtailment
  - Lower gross revenues for conventional generation resources
  - Lower average LMP and zonal prices
  - In general, all the simulations of challenging days revealed successful operation of the PJM real-time market.

Key Findings: Capacity Valuation

Range of Effective Load Carrying Capability (ELCC) of Different Renewable Resources in 20% and 30% Scenarios

Resource	ELCC (%)	PJM Manual 21 (Summer Peak Hour Average Capacity Factor)
Residential PV	57% - 58%	51%
Commercial PV	55% - 56%	49%
Central PV	62% - 66%	62% - 63%
Off-shore Wind	21% - 29%	31% - 34%
Onshore Wind	14% - 18%	24% - 26%

PJM Manual 21 defines the capacity value of the intermittent resource (in percentage terms) as the average capacity factor that the resources have exhibited in the last three years during the summer peak period. The two columns can be compared since they were based on the same hourly generation profiles.

The ELCC values are larger than the current class averages of 13% for wind and 38% for solar which were based on actual historical values. This is because the wind profiles used in the study assumed advanced turbine design expected to be available in the future, and therefore, the values reported here would be slightly higher than what has been historically observed in PJM. In addition, the study includes significantly more solar generation than actual historical and more diversely distributed.

Key Findings: Different Profile Years

Using Different Load and Wind Profile Years:

- To test impact of different profile years, in addition to the 2006 profile year, the load and wind profiles from years 2004 and 2005 were used in 2% BAU, 14% RPS, 20% LOBO, and 30% LOBO Scenarios.
- Although there was observable difference in operational and economic performance across the profile years, the overall differences were relatively small.

Sensitivity Analysis

- (LL): Low Load Growth: 6.1% reduction in demand energy compared to the base case
  - The base case assumed a PJM net energy forecast of 969,596 GWh in 2026 (excluding EKPC) based on the 2011 PJM Load Forecast Report. The 2014 Preliminary PJM Load Forecast report shows a net energy forecast of 889,841 GWh in 2026 excluding EKPC, i.e., a reduction of 8.2%.
- (LG): Low Natural Gas Price: AEO forecast of $6.50/MMBtu compared to $8.02/MMBtu in the base case
  - The base case assumed a gas price of $8.02/MMBtu based on the EIA Annual Energy Outlook 2012 Report Henry Hub. The AEO 2014 Early Release Report is forecasting $6.44/MMBtu for 2026
- (LL, LG): Low Load Growth & Low Natural Gas Price
- (LG, C): Low Natural Gas Price & High Carbon Cost: Carbon Cost $40/Ton compared to $0/Ton in the base case
- (PF): Perfect Wind & Solar forecast: Perfect knowledge of the wind and solar for commitment and dispatch

Key Findings: Sensitivity Analysis

- Sensitivity analysis key findings are:
  - Lower PJM System Load caused increased generation displacement of both Coal and Gas generation (details provided later in the Sensitivity tables)
  - Lower Natural Gas Prices caused an increase in Gas generation and a decrease in Coal generation
  - Lower Natural Gas Prices combined with a $40/Ton Carbon Tax caused a significant increase in CCGT operation and a decrease in Coal
  - Lower PJM Load combined with Lower Natural Gas Prices had minimal impact on CCGT operation because of offsetting impacts.
  - Production cost savings from renewable energy can vary significantly depending on assumptions about fuel prices, load growth, and emission costs. For example, compared to the base scenario, production cost savings in the 14% RPS scenario were 12.8% lower for the Low Load / Low Gas sensitivity and 39% higher for the Low Gas / High Carbon sensitivity.

Key Findings: New Transmission Lines and Upgrades for the Study

Scenario	765 kV New Lines (Miles)	765 kV Upgrades (Miles)	500 kV New Lines (Miles)	500 kV Upgrades (Miles)	345 kV New Lines (Miles)	345 kV Upgrades (Miles)	230 kV New Lines (Miles)	230 kV Upgrades (Miles)	Total (Miles)	Total Cost (Billion)	Total Congestion Cost (Billion)
2% BAU	0	0	0	0	0	0	0	0	0	$0	$1.9
14% RPS	260	0	42	61	352	35	0	4	754	$3.7	$4.0
20% Low Offshore Best Onshore	260	0	42	61	416	122	0	4	905	$4.1	$4.0
20% Low Offshore Dispersed Onshore	260	0	42	61	373	35	0	49	820	$3.8	$4.9
20% High Offshore Best Onshore	260	0	112	61	363	122	17	4	939	$4.4	$4.3
20% High Solar Best Onshore	260	0	42	61	365	122	0	4	854	$3.9	$3.3
30% Low Offshore Best Onshore	1800	0	42	61	796	129	44	74	2946	$13.7	$5.2
30% Low Offshore Dispersed Onshore	430	0	42	61	384	166	44	55	1182	$5.0	$6.3
30% High Offshore Best Onshore	1220	0	223	105	424	35	14	29	2050	$10.9	$5.3
30% High Solar Best Onshore	1090	0	42	61	386	122	4	4	1709	$8	$5.6

Locations or these transmission facilities are provided in the maps included in the "Transmission Analysis" Section of the Task 3a Report.

Key Findings: Reserve Analysis

- Significant penetration of renewable energy will increase the Regulation requirement and will increase the frequency of utilization of these resources.
  - The study identified a need for an increase in the regulation requirement even in the lower wind penetration scenario (2% BAU), and the requirement would have noticeable increases for higher penetration levels.
  - The average regulation requirement for the load only (i.e. no wind or PV) case was 1,204 MW.
  - This requirement increases to about 1,600 MW for the 14% RPS scenario, to a high of 1,958 MW in the 20% scenarios and then 2,737 MW in the 30% scenarios.
  - No additional primary reserves (synchronized or non-synchronized) or secondary reserves were required for contingency or uncertainty.

Key Findings: Sub-Hourly Analysis

- In general, all the simulations of challenging days revealed successful operation of the PJM real-time market.
  - That the amounts of reserve and operating practices assumed for the study were adequate.
  - The assumed reserves criteria were adequate to cover forecast error and variability, given the current number of existing CTs.
- Although there were occasionally periods of reserve shortfalls and new patterns of CT usage, there were no instances of unserved load.
  - New patterns of CT usage include (a) compensating for forecast errors, (b) addressing the load requirements before and after the daily solar generation.
- The level of difficulty for real-time operations largely depends on the day-ahead unit commitment.
- Higher penetrations of renewable energy (20% and 30%) create operational patterns that are significantly different than what is common today.

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Key Findings: Cycling Cost Analysis

- Increased renewable integration results in increased cycling on existing fossil generation.
    - CCGT Units perform majority of the On/Off cycling in the scenarios, with the coal units performing the load follow cycling.
    - On an absolute scale, the cost of On/Off and Significant Load Follow increases the most on Supercritical and Combined Cycle Units.
- In almost all of the scenarios, the coal and combined cycle units perform increasing amounts of cycling; resulting in higher cycling related VOM cost and reduced Baseload VOM Cost, where:
    - Total Variable O&M (VOM) Cost = Baseload VOM + Cycling VOM.
- This analysis focused on VOM due to cycling
    - Increased cycling may also increase forced outage rates, but quantifying such reliability impacts was outside the scope of this study.

Key Findings: Cycling Emissions Analysis

- The main observations and conclusions from this analysis are:
  - Emissions from coal plants comprise 97% of the NOx and 99% of the SOx emissions
  - For scenarios that experience increased emissions due to cycling, the increases are dominated by supercritical coal emissions.
  - NOx and SOx rates (lbs./MWh) increase at low loads for coal plants and decrease for CTs.
  - Load-follow cycling is the primary contributor of cycling related emissions.
  - Including the effects of cycling in emissions calculations does not significantly change the level of emissions for scenarios with higher levels of renewable generation. However, on/off cycling and load-following ramps do increase emissions over steady state levels. This analysis has provided quantified data on the magnitudes of those impacts.

Key Findings: Market Analysis

- Dynamic Procurement of Regulation
    - The amount of "additional" Regulation (over and above the current NERC based requirements) needed at a given time is a function of the amount of wind and solar power production at that time.
    - The amount of additional Regulation can be optimized each hour to be the "right" amount for the wind + solar generation in that hour, based on short-term wind +solar forecast for that hour.
- Operating-Day Recommitment Process
    - Errors in day-ahead wind + solar forecasts provide significant challenges to real-time operations (especially over-forecasting wind + solar)
    - With present practices, forecast errors are compensated by re-dispatch of committed generation and commitment of CT units in the Real-Time market.
    - System efficiency could be improved with a short-term (say 4-6 hour) economic recommitment process during the operating day, based on a 4-6 hour-ahead wind + solar forecast.
- Recommendations from investigation of Industry Practices

Key Findings: Mitigations

- Further Support for Mid-Term Commitment & Better Wind/Solar Forecast
  - Addition of a mid-term commitment (e.g., 4 hours-ahead) with updated wind and solar forecast will allow for use of more accurate wind and solar forecasts in a time frame when commitments from intermediate units can still be adjusted, resulting in significantly less CT commitment in real-time.
- Benefits of Energy Storage to Provide Reserve
  - Reduction in regulation reserve requirements by using Energy Storage caused a small drop in PJM total production cost. These results should not be generalized, since we did not evaluate the benefits of the full range of service offerings of energy storage in PJM.
- Power Plant Cycling
  - Cycling Costs when accounted for as VOM adders increases by about 2% the reduction in Production Costs of 30% LOBO relative to 2% BAU scenarios.
- Improved Ramp Rate
  - Improving Ramping of large Coal Plants would result in reduction in ramp constrained generation, fewer CTs committed, lower LMPs, less congestion, and more flexible operations.

Major Recommendations

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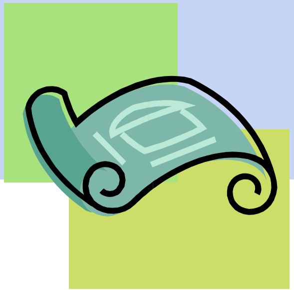
Incremental Improvements

- The study findings in general support the notion that PJM system, with adequate transmission and operating reserves, will not have any significant issue absorbing the higher levels of renewable energy penetration considered in the study.
  - In performing this project, the GE Team has come to the conclusion that PJM's current energy scheduling practices already incorporates recommendations from previous renewable energy integration studies.
  - For example, day-ahead wind/solar forecasting is used in the daily unit commitment process.
  - Hence, our recommendations should be viewed as potential incremental improvements suggested by our findings.



Recommendations for Adjustments to Regulation Requirements

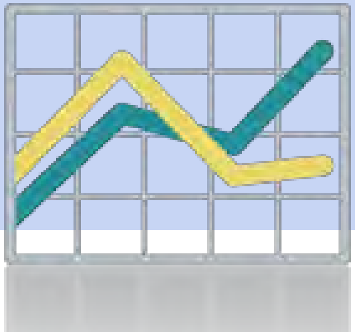
- Current PJM Regulation Requirements since December 1, 2013:
  - Uniform for all on-peak hours (0500 - 2359) at 700 effective MW and all off-peak hours (0000 - 0459) at 525 effective MW.
  - Previously, regulation commitment was based on 0.70% of valley load during off-peak hours and 0.70% of peak load during on-peak hours.
  - Earlier, at the start of this study, regulation commitment was based on 1% of valley load during off-peak hours and 1% of peak load during on-peak hours, which were used to determine the base regulation requirement in this study.
- This study modeled additional Regulation Requirement to mitigate renewable energy variability.
- It is recommended that PJM develop a similar scheme to determine additional regulation requirements based on forecasted levels of wind and solar production (day-ahead and shorter term).
- Due to the size and geographic spread of the PJM system, no additional primary reserve (synchronized or non- synchronized) or secondary reserves are required to cover forecast uncertainty.

Recommendations for Renewable Energy Capacity Valuation

- Capacity value of renewable energy has a slightly diminishing return at progressively higher penetration, and the LOLE/ELCC approach provides a rigorous methodology for accurate capacity valuation of renewable energy.
- PJM may want to consider an annual or bi-annual application of methodology in order to calibrate its renewable capacity valuation methodology in order to occasionally adjust the applicable capacity valuation of different classes of renewable energy resources in PJM.

Recommendation for Mid-Term Commitment & Better Wind and Solar Forecast

- Mid-Term Commitment & Better Wind and Solar Forecast
  - Addition of a mid-term commitment (e.g., 4 hours-ahead) with updated wind and solar forecast will allow for use of more accurate wind and solar forecasts in a time frame when commitments from intermediate units can still be adjusted, resulting significantly less CT commitment in real-time than the baseline 14% RPS simulation for this day, as measured both by number of CTs and MW dispatched from CTs.
  - For instance, a wind and solar forecast feature be added to the current PJM Intermediate Term Security Constrained Economic Dispatch (IT SCED) application, with a longer look ahead of up to 4 hours. IT SCED is currently used to commit CT's and guides the Real Time SCED (RT SCED) by looking ahead up to two hours.



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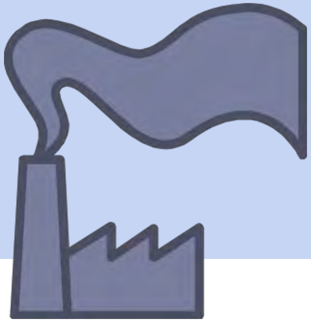
Recommendation for Exploring Improvements to Ramp Rate Performance

- Ramp-rate limits on the existing baseload generation fleet may constrain PJM's ability to respond to rapid changes in net system load in some operating conditions.
- It is recommended that PJM explore the reasons for ramping constraints on specific units, determine whether the limitation are technical, contractual, or otherwise, and investigate possible methods for improving ramp rate performance.



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Wind, Solar, and Load Profile Development
AWST + GE
[15 Minutes]

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Wind Profiles

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Wind and Solar Data Development

- Develop synthetic power output profiles and power forecasts for theoretical wind and solar generating facilities.
  - Modeled Numerical Weather Prediction (NWP) data from the Eastern Wind Integration and Transmission Study[1] (EWITS) was used as input.
  - Theoretical wind + solar power plants within the PJM interconnection region were obtained with objective site selection process.
  - Wind power output for onshore and offshore sites was computed using a composite of current industry standard power curves.
  - Wind sites were selected based on a seamless map of predicted mean wind speeds at 80 m height within the PJM Renewable Resource Boundary.
  - Solar power output for centralized and distributed scale sites is based on current technology types and commercially available PV modules.
  - Four-hour, six-hour, and next-day wind and solar power forecasts were developed using state-of-art synthetic forecasting tools.
  - All results were validated against several observed measurements.

[1] http://www.nrel.gov/docs/fy11osti/47078.pdf

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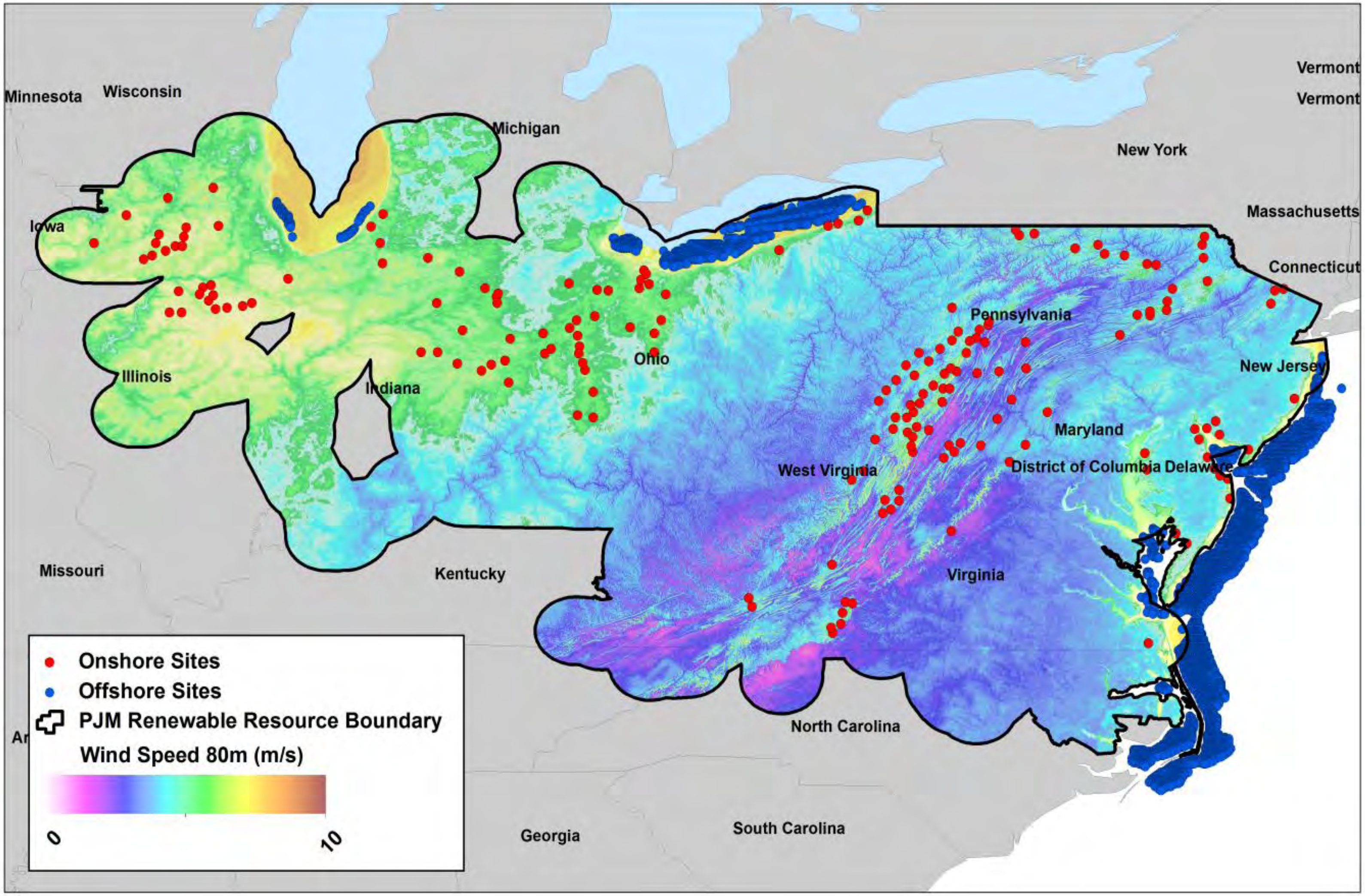
Wind Study Assumptions

- Hypothetical wind farm locations and wind simulations from EWITS study are within PJM Renewable Resource Boundary.
- Onshore and Offshore wind sites avoid exclusion (no build) areas.
- PJM queue sites are modeled at EWITS location with queue capacity.
- The mean speeds are based on AWST's wind maps adjusted to the year of the simulation for the selected hub heights of 80 m and 100 m.
- The power curve represents the average power output that would be expected from an industry standard wind turbine based on the appropriate International Electrotechnical Commission (IEC) class.
- In order to account for advances in turbine technology since the EWITS data sets were created, the composite power curves used in that study were updated with larger, more powerful turbines likely to be used for future wind farms.
- IEC-1 and IEC-2 composites were used at 80 m hub height, while IEC-3 and the offshore composite were used at 100 m.

PJM Renewable Resource Boundary and Hypothetical Onshore & Offshore Wind Sites



Solar Profiles

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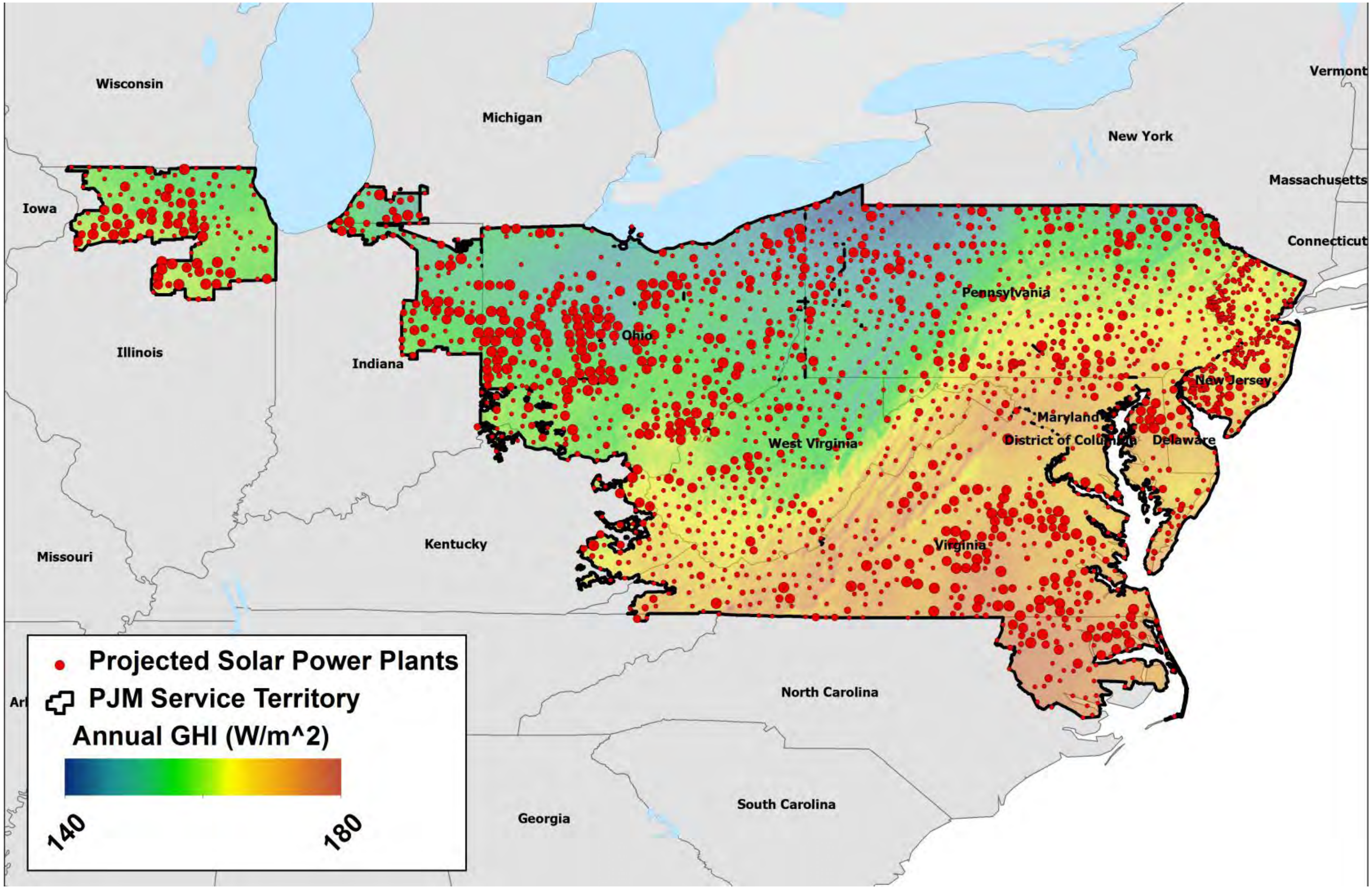
Solar Study Assumptions - Centralized

- Assumptions used to create the hypothetical centralized (utility) solar sites:
  - Sites screened by capacity factor
  - Gross power density of 45 MW/sq. km
  - Sites range in capacity from 10-100 MW
  - Minimum 10-25 km separation between sites
  - Each centralized site is greater than 1 MW
- Queue sites modeled at planned capacity and location
- Exclusions similar to wind sites
- Irradiance simulations from EWITS study
- Convert irradiance to 10-minute power output using composite fixed thin film solar PV panels tilted to latitude and single axis tracking mono-crystalline PV panels tilted to latitude
- Simulate solar power forecast for each hypothetical solar facility

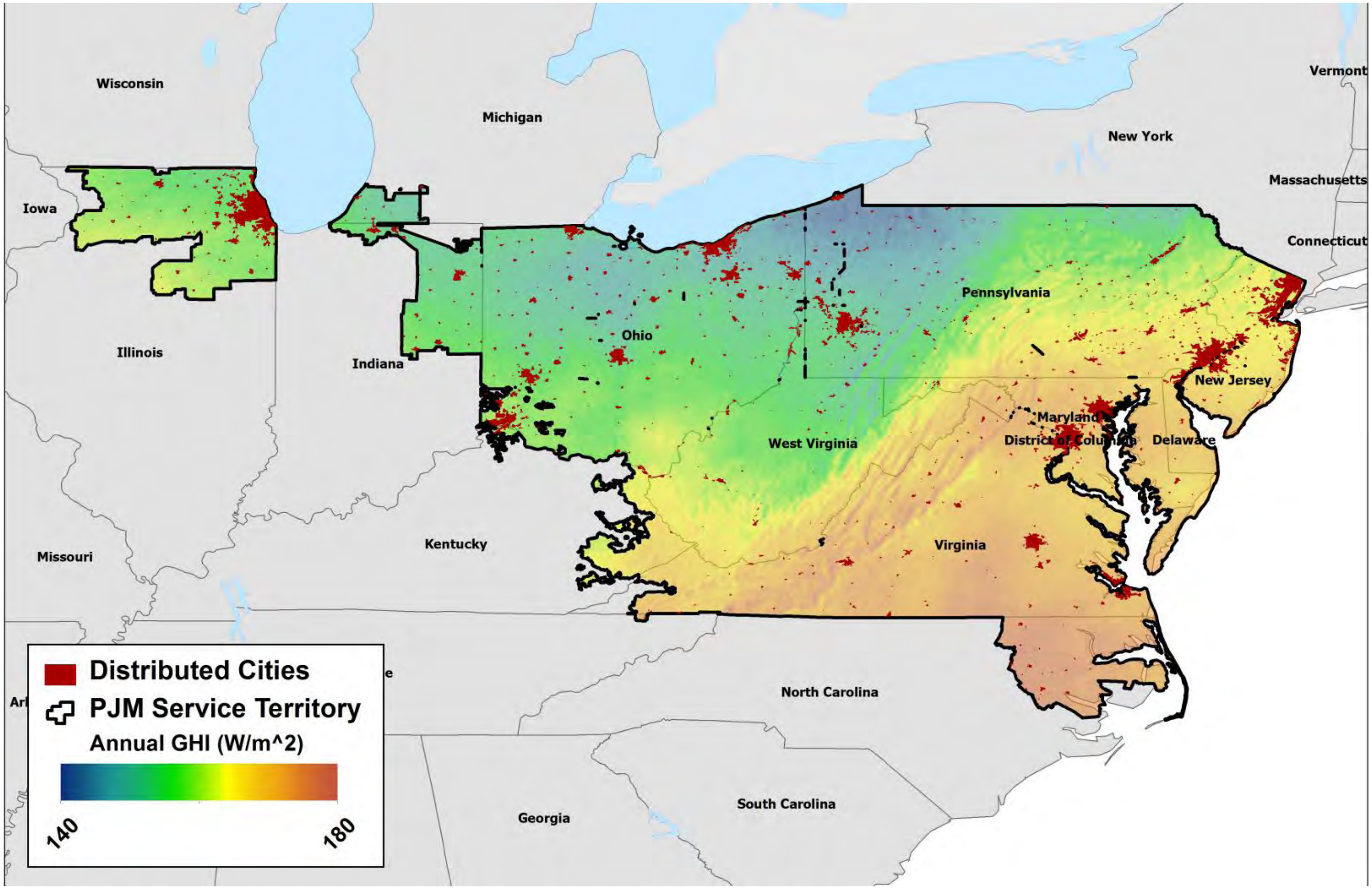
PJM Service Territory and Hypothetical Centralized Solar Sites



Solar Study Assumptions - Distributed

- Assumptions used to create the hypothetical distributed (rooftop) solar data:
  - Commercial – NLCD Classification: high-intensity; fixed panels tilted to latitude and south facing
  - Residential – NLCD Classification: medium-intensity; fixed, mix of tilt and azimuths
- Queue sites modeled at planned capacity and location
- Commercial distributed (250-1000 kW) + Residential distributed (1-10 kW)
- Irradiance simulations from EWITS study
- Convert irradiance to 10-minute power output using composite solar technology efficiencies
  - Commercial: fixed panel mono-crystalline PV tilted to latitude
  - Residential: fixed panel mono-crystalline PV mixed azimuth and tilt
- Simulate distributed solar power forecast for each city included in study

Map Of PJM Service Territory and Cities With Distributed Solar



Load Profiles

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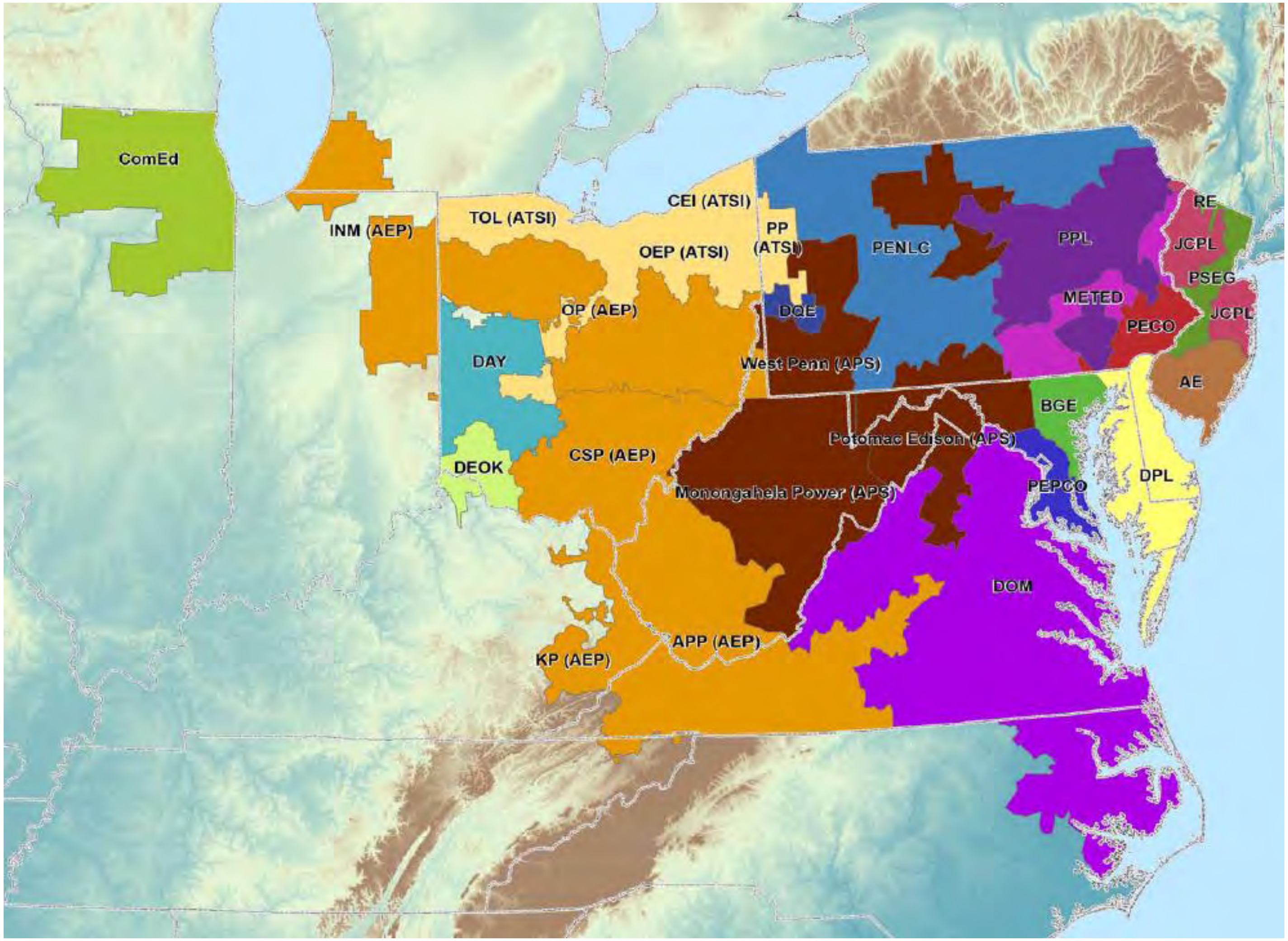
Load Profile Development

- The load data used in the hourly modeling is from the Ventyx Energy Velocity Suite dataset.
  - Hourly load at the PJM load zone level for the years 2004, 2005 and 2006 was used to establish load profiles.
  - The Ventyx load zones correspond to the zones in the PJM Load Forecast Report with additional breakdown of the AEP and DEOK zones.
    - AEP is broken into Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company.
    - DEOK is broken into Duke Energy Ohio and Duke Energy Kentucky.
  - As a data quality check, the annual PJM (excluding ATSI and DEOK) energy for years 2004, 2005 and 2006 from the Ventyx dataset were compared to the PJM RTO level loads posted on the PJM website.
  - The variations in annual energy were less than 0.5% in each case.

PJM Load Zone Geographical Representation January 2011



Source: PJM Load Forecast Report January 2011

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Load Profiling Approach

- The historical loads for each PJM load zone for all hours of the years 2004, 2005, and 2006 were time-synchronized with the wind/solar power data synthesized in the mesoscale model development.
  - In this manner the net load (i.e. load minus wind minus solar) could be used for the dispatch of the conventional (i.e. dispatchable) resources on the system.
  - The net load concept is critical to determining the operating impacts that wind and solar generation may have for two reasons:
    - Power produced by wind and solar is essentially used as available (i.e. wind and solar are a non-dispatchable resource), and
    - The variability that must be compensated by the fleet of dispatchable resources is the combination of the variability introduced by wind, by solar, and by the load which are somewhat correlated.
  - Since the profiles of wind, solar and the load are somewhat correlated same profile year should be used for wind, solar, and load profiles.

Break

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Scenario Development & Analysis
GE
[15 Minutes]

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Study Scenarios

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Key Assumptions

- Eastern Interconnect system was simulated
- Renewable plants were connected to higher voltage busses
- Remaining PJM coal plants were assumed to have emissions control technology
- Renewable resources were curtailed when dispatch will impact nuclear operation
- Only primary fuel was modeled
- Existing operating reserve practice was used for 2P BAU scenario, statistical analysis was used to modify reserves for others
- 2026 run year used 2006 load and renewable hourly shapes.
- 2026 data was updated based on PJM input on coal retirements, gas repowers, and new builds

Study Scenarios

Scenario	Renewable Penetration in PJM	Wind/Solar (GWh)	Wind + Solar Siting	Comments
2% BAU	Reference	Existing Wind + Solar	Existing Plants (Business as Usual)	Benchmark Case for Comparing Scenarios
14% RPS	Base Case 14%	109 / 11	Per PJM Queue & RPS Mandates	Siting based on PJM generation queue and existing state mandates
20% LOBO	20%	150 / 29	Low Offshore + Best Onshore	Onshore wind selected as best sites within all of PJM
20% LODO	20%	150 / 29	Low Offshore + Dispersed Onshore	Onshore wind selected as best sites by state or region
20% HOBO	20%	150 / 29	High Offshore + Best Onshore	High offshore wind with best onshore wind
20% HSBO	20%	121 / 58	High Solar + Best Onshore	High solar with best onshore wind
30% LOBO	30%	228 / 48	Low Offshore + Best Onshore	Onshore wind selected as best sites within all of PJM
30% LODO	30%	228 / 48	Low Offshore + Dispersed Onshore	Onshore wind selected as best sites by state or region
30% HOBO	30%	228 / 48	High Offshore + Best Onshore	High offshore wind with best onshore wind
30% HSBO	30%	179 / 97	High Solar + Best Onshore	High solar with best onshore wind

Total PJM Wind and Solar Capacity for Study Scenarios

Scenario	Onshore Wind (MW)	Offshore Wind (MW)	Centralized Solar (MW)	Distributed Solar (MW)	Total (MW)
2% BAU	5,122	0	72	0	5,194
14% RPS	28,834	4,000	3,254	4,102	40,190
20% LOBO	39,452	4,851	8,078	10,111	62,492
20% LODO	40,942	4,851	8,078	10,111	63,982
20% HOBO	21,632	22,581	8,078	10,111	62,402
20% HSBO	32,228	4,026	16,198	20,294	72,746
30% LOBO	59,866	6,846	18,190	16,907	101,809
30% LODO	63,321	6,846	18,190	16,907	105,264
30% HOBO	33,805	34,489	18,190	16,907	103,391
30% HSBO	47,127	5,430	27,270	33,823	113,650

Renewable Energy Penetration for the rest of the Eastern Interconnection

- Renewable Energy in the rest of the Eastern Interconnection was distributed according to EWITS Scenario 2
- Distribution Ratio (%) was calculated for each region from this table

Ratio Equation:

$$\frac{\text{(EWITS Scen2 NERC Region x RE)}}{\text{(EWITS Scen2 Total RE – EWITS Scen2 PJM RE)}}$$

Where RE: Renewable Energy

NERC Region Renewable Energy Distribution Ratio

Region	EWITS Scenario 2 Wind Energy (GWh)	Rest of EI NERC region RE ratio
ISO-NE	46,000	7%
MISO+MAPP	288,000	45%
NYISO	48,000	7%
SERC	16,000	2%
SPP	245,000	38%
TVA	4,000	1%
Total - PJM	**647,000**	**100%**

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Renewable Mix

- 14% RPS Scenario meets RPS targets for states within PJM footprint
- Wind/Solar Split
  - Distributed solar is mix of residential (20%) and commercial (80%)
- Transmission system is built out for each scenario based on wind/solar generation ratings and locations

Scenario	Onshore Wind	Offshore Wind	Centralized Solar	Distributed Solar
14% RPS	86%	14%	50%	50%
Low Offshore	90%	10%	50%	50%
High Offshore	50%	50%	50%	50%
High Solar	90%	10%	50%	50%

Scenario	PJM % RE	EI % RE
14 RPS	14%	10%
Low Offshore	20%	15%
High Offshore	20%	15%
High Solar	20%	15%
Low Offshore	30%	20%
High Offshore	30%	20%
High Solar	30%	20%

Hourly GE MAPS Analysis (GE) [15 Minutes]

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Operational Performance
(Results are for the PJM RTO Only)

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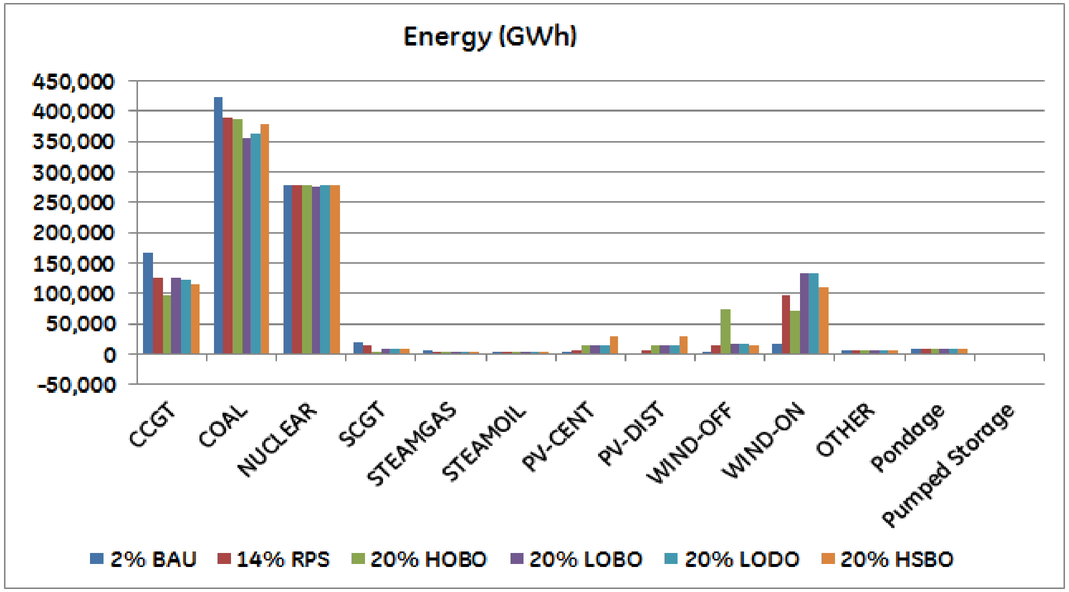
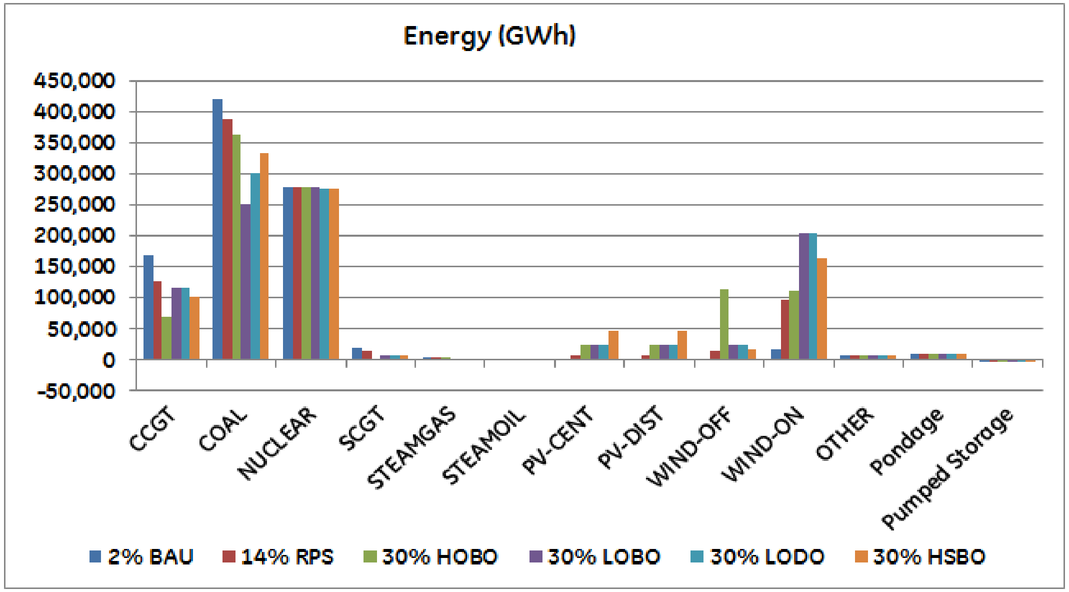
Energy Generation by Unit Type (GWh)



- CCGT & Coal generation decreases as renewable penetration increases.



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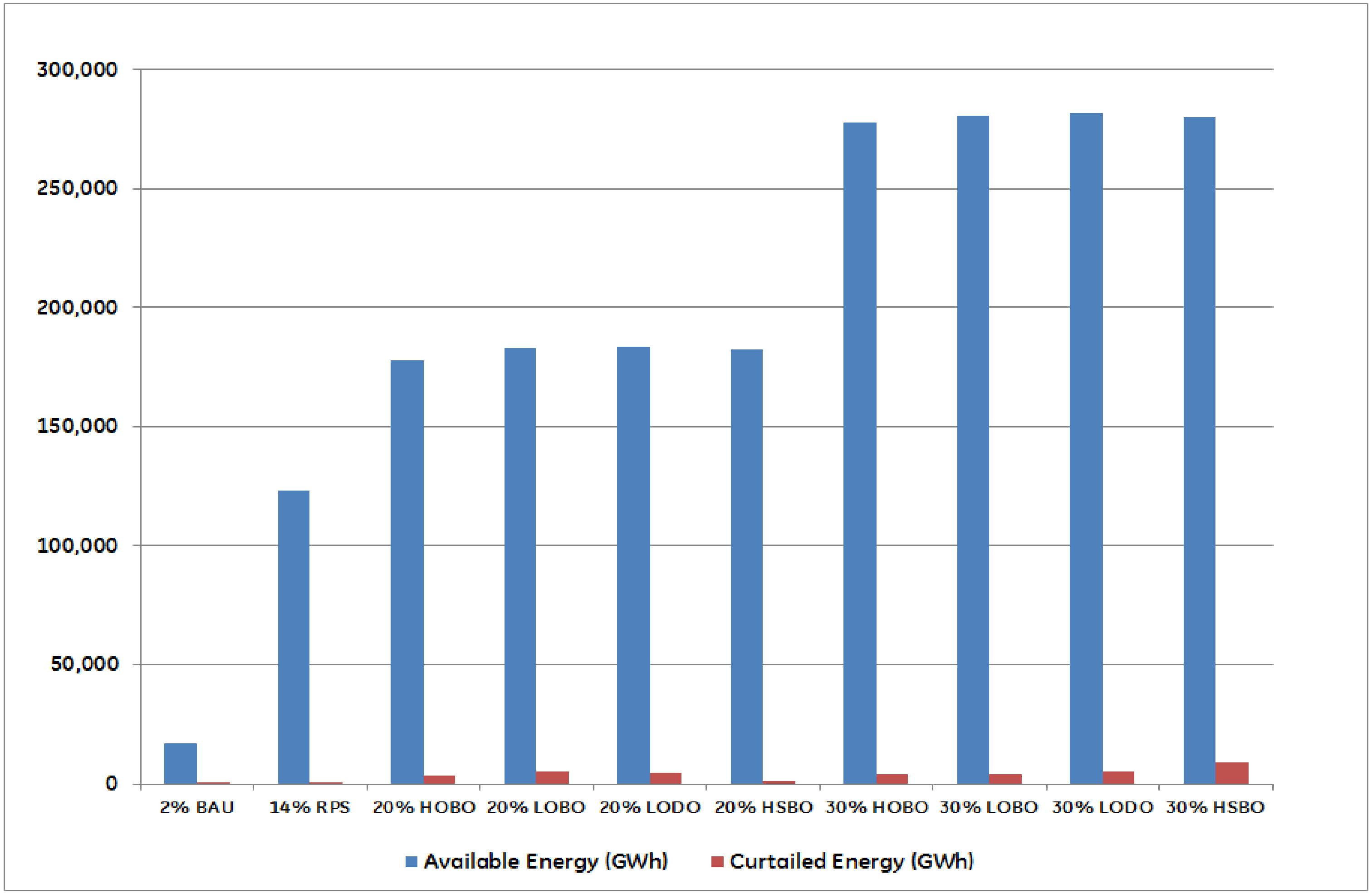
Delivered and Curtailed Renewable Energy



- Overall, very little curtailment
- Highest curtailment seen in the 30% HSBO scenario (mostly due to local congestion)

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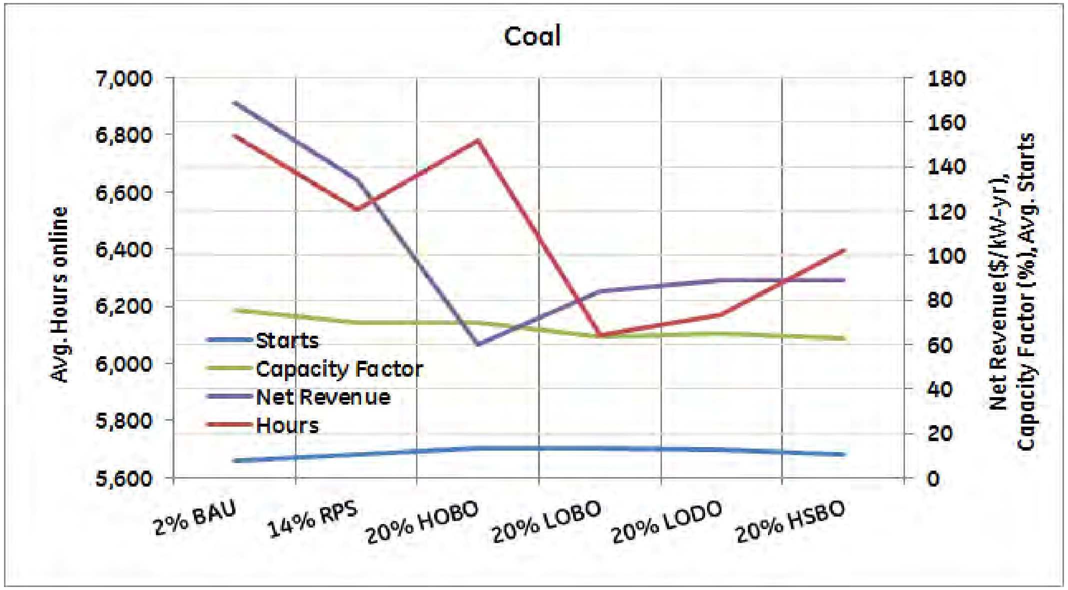
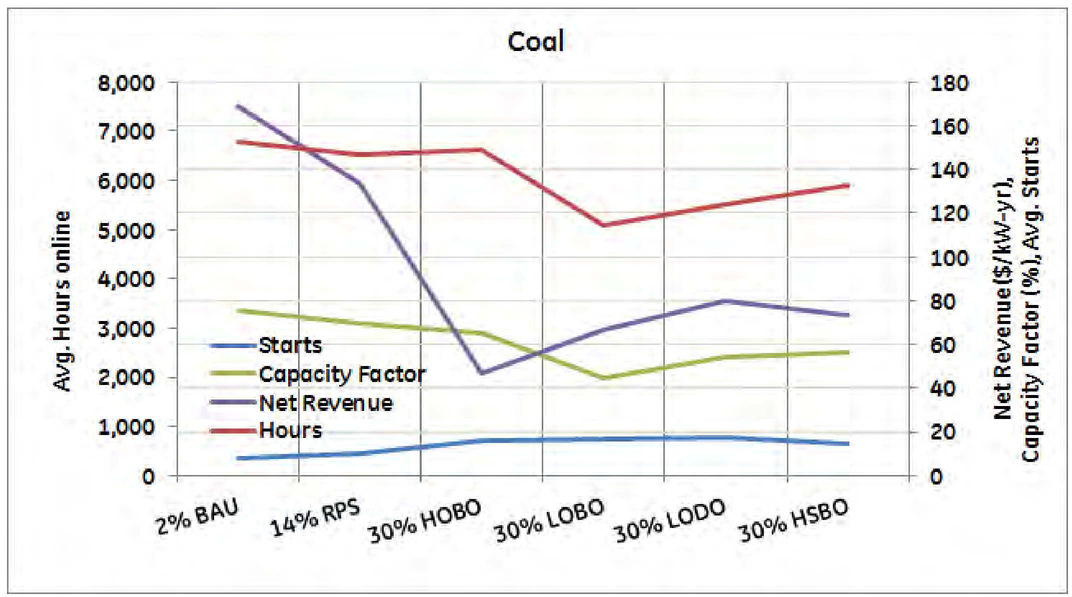
Performance of Coal Units



- Coal generation starts increase and hours online decrease, indicating increased cycling due to increased renewable penetration.
- Net Revenue decreases significantly.



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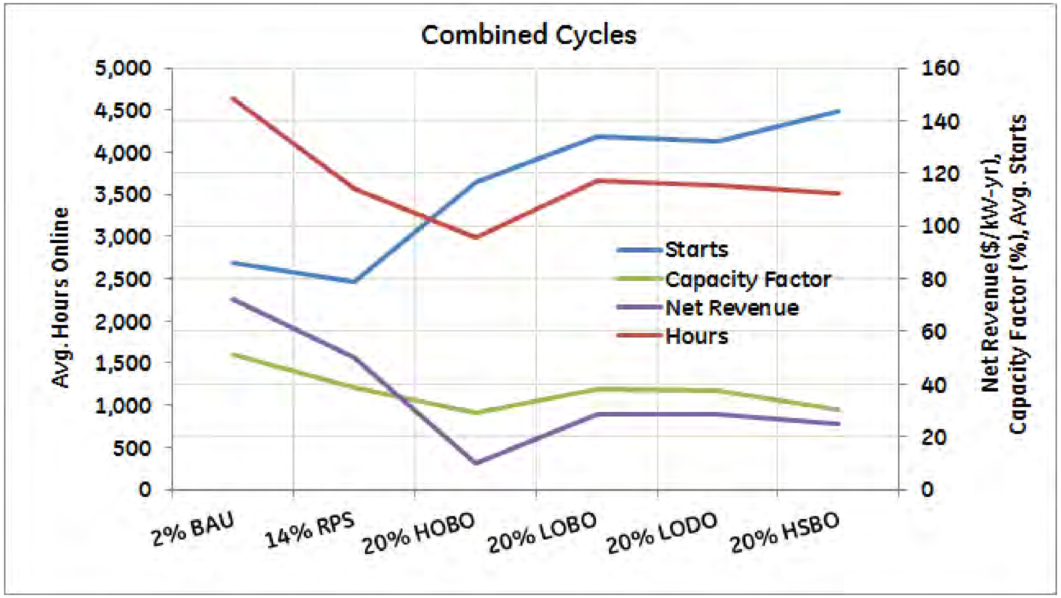
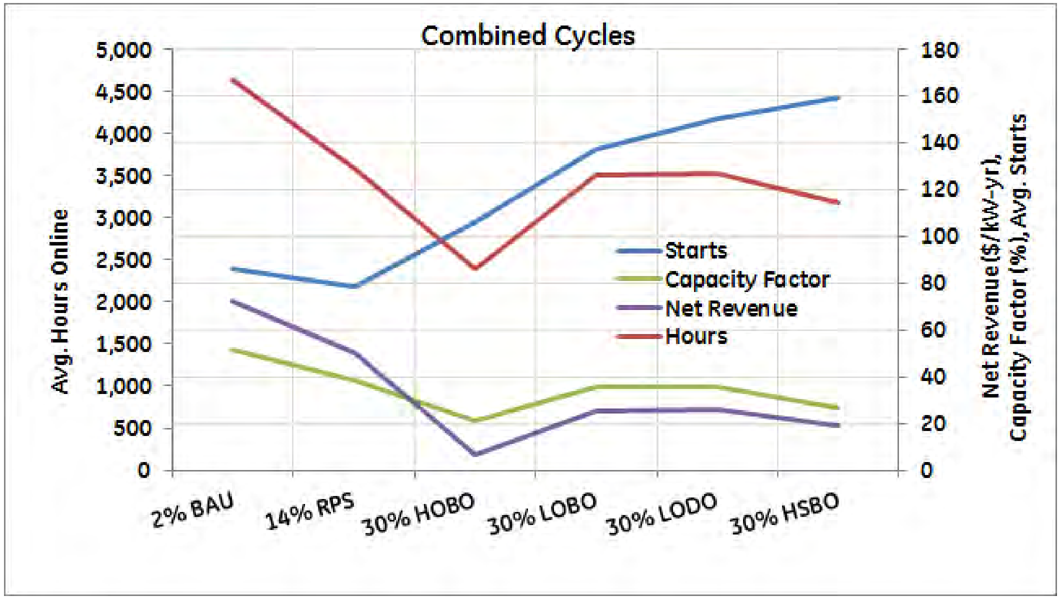
Performance of Combined Cycle Units



- Similar to Coal generation, CCGT starts increase and hours online decrease, indicating increased cycling due to increased renewable penetration.
- Net Revenue decreases significantly.



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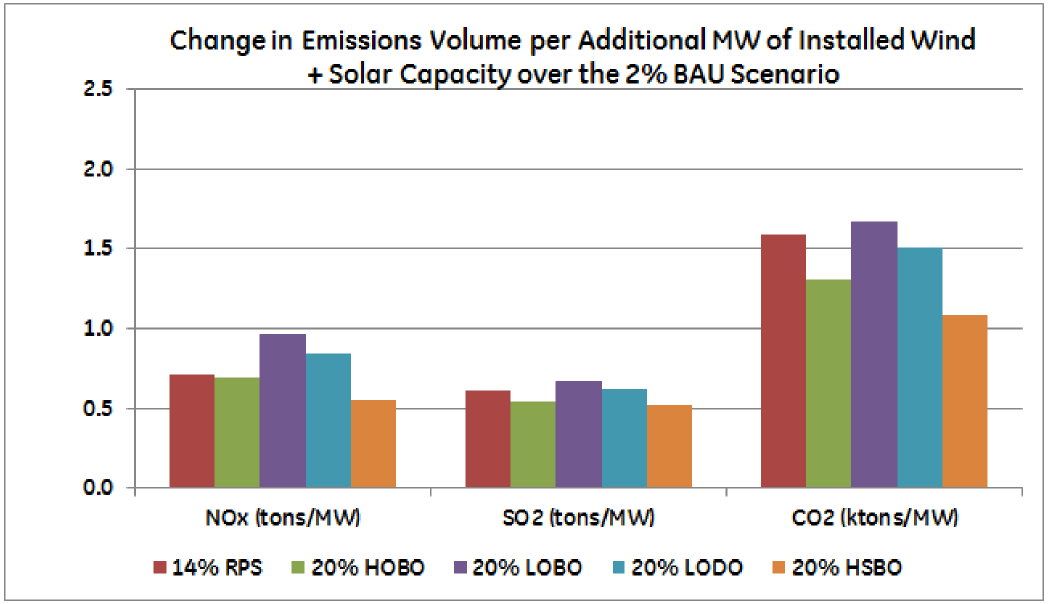
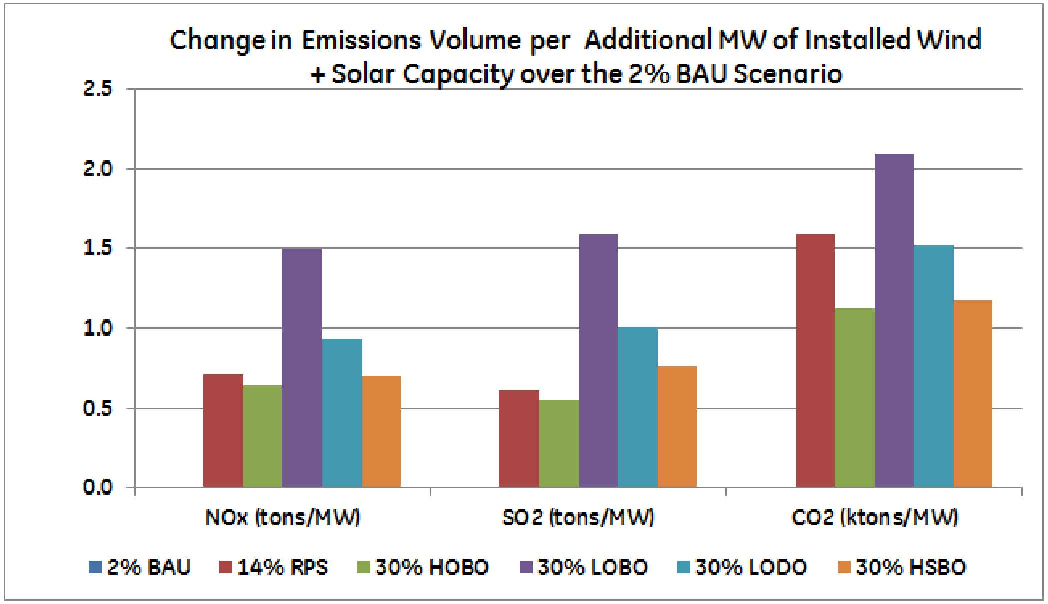
Environmental Emissions



- Emission volumes are reduced with increased renewable penetration.



Economic Performance

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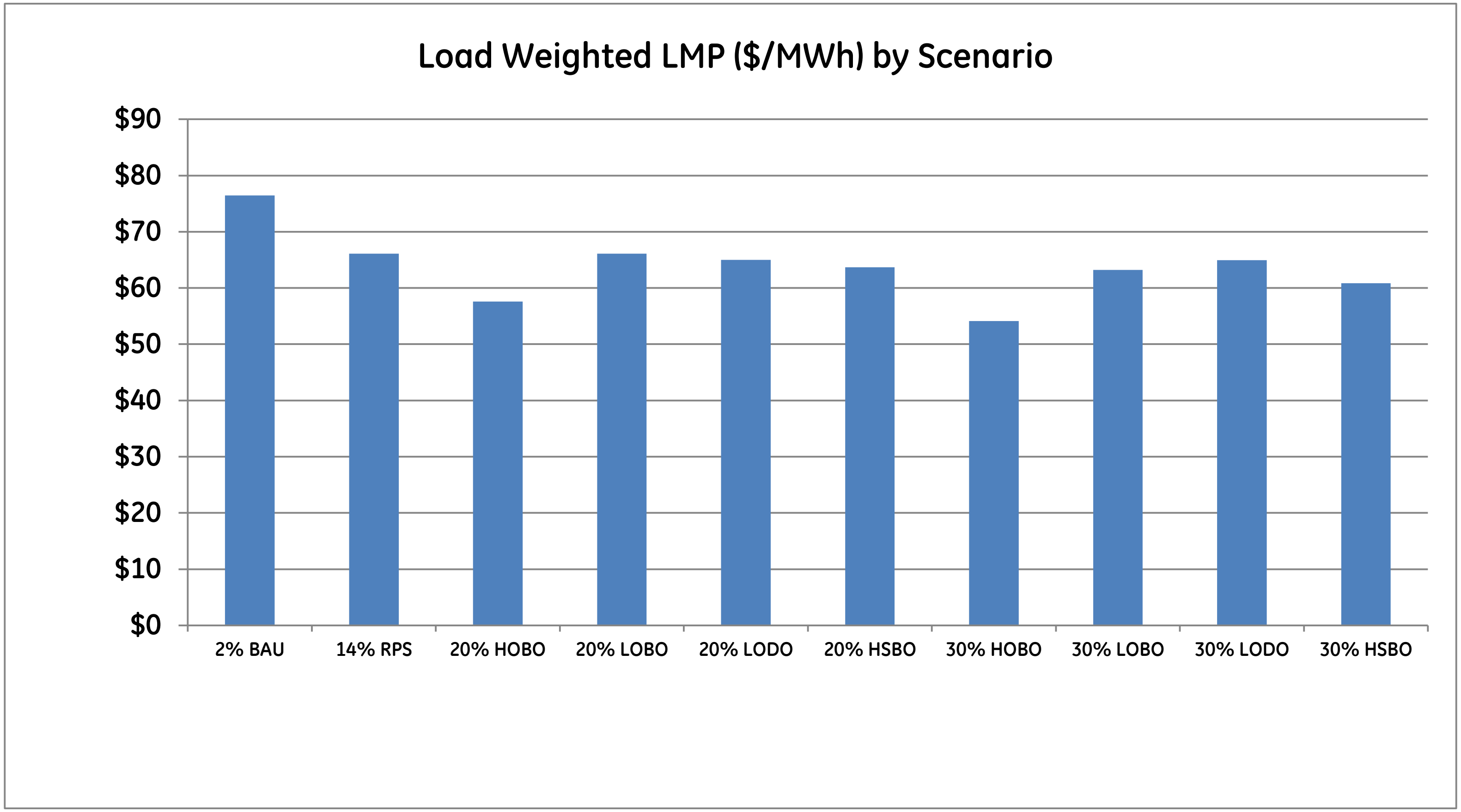
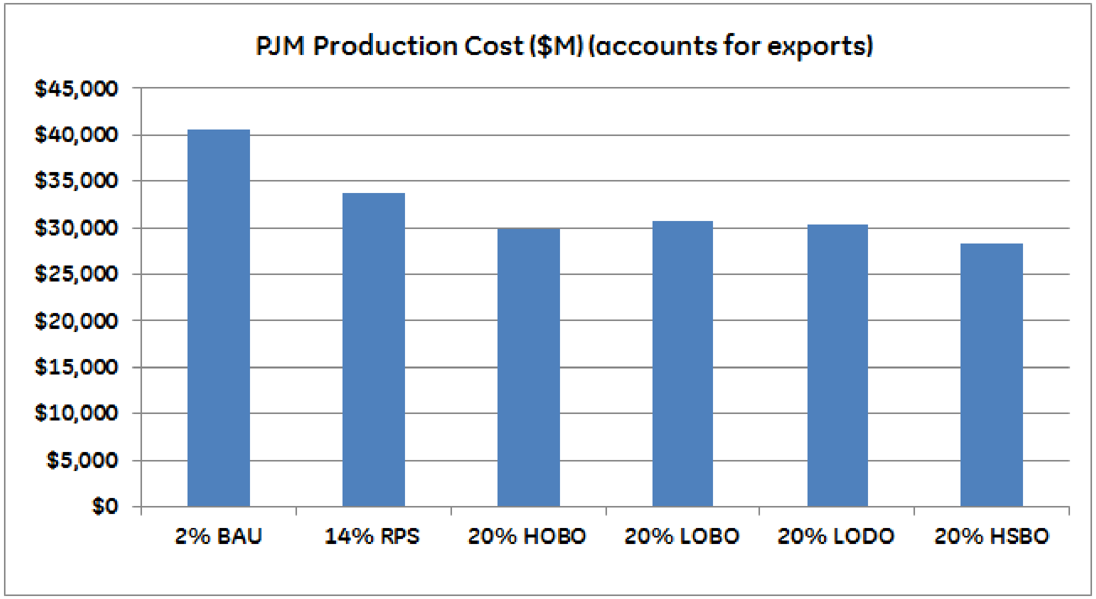
Load Weighted LMP



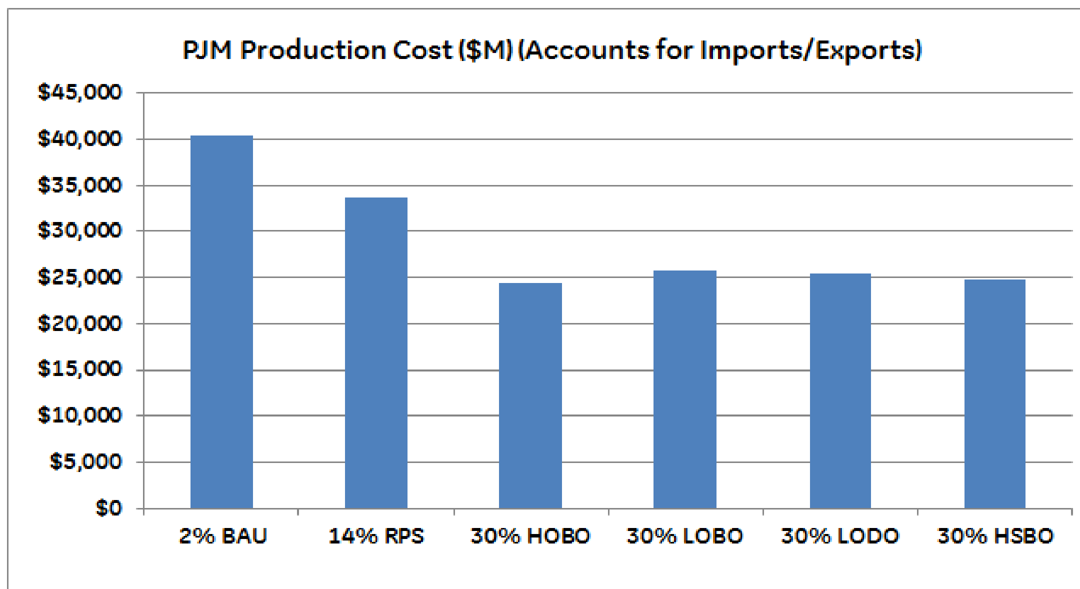
Geographic variation still exist in all scenarios.

PJM Production Cost ($M)

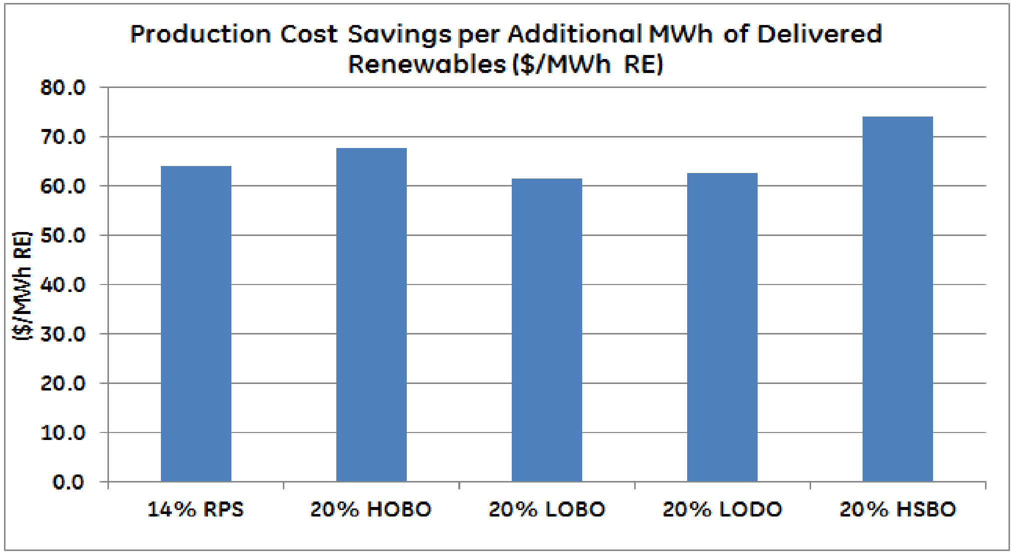


- Production Cost decreases with increased renewable penetration.

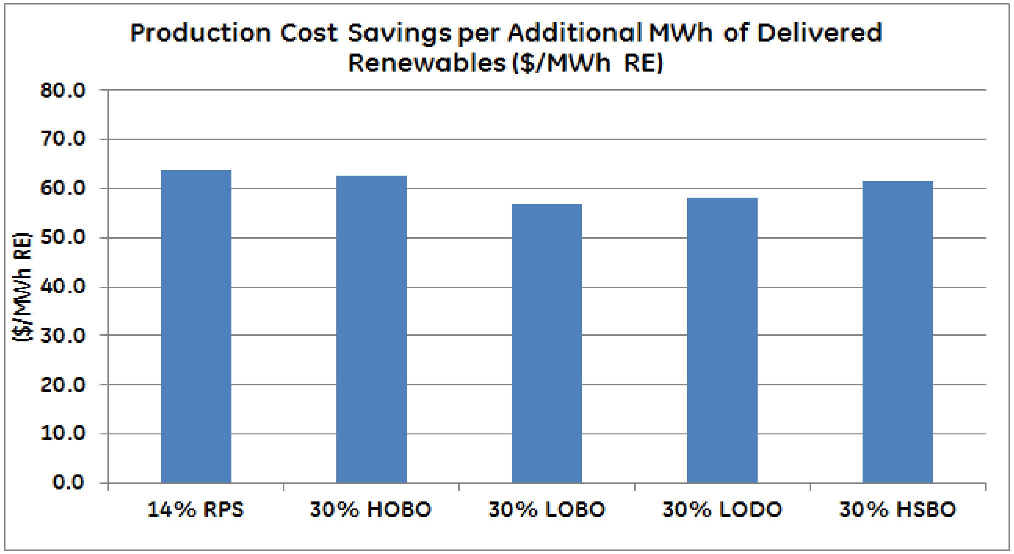
- Production Costs are defined as the System Variable Costs (i.e., Fuel, VOM, any Emission Tax or Allowance Costs) and Start-up Costs, adjusted for Import Purchases and Export Sales.
- Capital and Fixed costs have not been taken into account.



Production Cost Savings per Additional MWh or Renewable Energy



- Production Cost Savings are the Reduction in Production Costs in each scenario divided by the Additional Renewable Energy over the 2% BAU scenario.



Production Cost Savings due to Additional Renewables, Adjusted for Estimated Transmission Costs

Scenario	Renewable Energy Delivered (GWh) over the 2% BAU Scenario (GWh)	Production Cost Savings over the 2% BAU Scenario ($B/Year)	Production Cost Savings per MWh of Delivered Renewables ($/MWh RE)	Annualized Transmission Costs ($M/Year)	Transmission Costs per MWh of Delivered Renewables ($/MWh RE)	Production Cost Savings Adjusted for Transmission Costs ($/MWh RE)
14% RPS	105,642	-6.8	63.9	555	4.5	59.4
20% HOBO	157,552	-10.6	67.4	660	3.8	63.7
20% LOBO	160,490	-9.9	61.4	615	3.5	58.0
20% LODO	161,542	-10.1	62.6	570	3.2	59.4
20% HSBO	164,253	-12.1	73.8	585	3.2	70.6
30% HOBO	256,400	-16.1	62.7	1,635	6.0	56.8
30% LOBO	259,428	-14.8	56.9	2,055	7.4	49.5
30% LODO	259,345	-15.1	58.1	750	2.7	55.4
30% HSBO	253,918	-15.6	61.6	1,200	4.4	57.2

- Production Cost is sum of Fuel Costs, Variable O&M Costs, Any Emission Tax/Allowance Cost, and Start-Up Costs, adjusted for Import Purchases and Export Sales.
- A carrying charge of 15% was used to calculate the annual transmission cost. Transmission cost refers to the estimated capital cost of additional transmission.

Hourly Analysis Key Findings

- Even at 30% penetration, results indicate that the PJM system can handle the additional renewable integration with sufficient reserves and transmission build out.
- The principal impacts of higher penetration of renewable energy into the grid include:
  - Lower Coal and CCGT generation under all scenarios
  - Lower emissions of criteria pollutants and greenhouse gases
  - No loss of load and minimal renewable energy curtailment
  - Lower system-wide production costs
  - Lower generator gross revenues
  - Lower average LMP and zonal prices

Hourly Analysis Key Findings (Continued)

- On average for all scenarios, ~36% displacement from coal-based Generation and ~39% displacement from gas-based generation (of the total displacement caused by the renewable generation) as compared to the 2% BAU Scenario.
- On average for all scenarios, the production cost savings due to increased renewable energy was ~$63/MWh (incremental production cost savings / incremental renewable energy MWhs produced). If we take into account the annualized costs associated with the transmission overlay, the production cost savings of additional renewable energy (RE) becomes ~$59/MWh RE.
- Emission Reduction is seen in all scenarios.

Hourly Analysis Key Findings (Continued)

Using Different Load and Wind Profile Years:

- To test impact of different profile years, in addition to the 2006 profile year, the load and wind profiles from years 2004 and 2005 were used in 2% BAU, 14% RPS, 20% LOBO, and 30% LOBO Scenarios.
- Although there was observable difference in operational and economic performance across the profile years, the overall differences were relatively small.

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Sensitivity Analysis

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Sensitivity List

- (LL): Low Load Growth: 6.1% reduction in demand energy compared to the base case
- (LG): Low Natural Gas Price: AEO forecast of $6.50/MMBtu compared to $8.02/MMBtu in the base case
- (LL, LG): Low Load Growth & Low Natural Gas Price
- (LG, C): Low Natural Gas Price & High Carbon Cost: Carbon Cost $40/Ton compared to $0/Ton in the base case
- (PF): Perfect Wind & Solar forecast: Perfect knowledge of the wind and solar for commitment and dispatch

Comparison of All BAU Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)
2% BAU	904,998	17,217	47,390	192,025	421,618	47,390	40,470	70,023	70,947	76.5
	Delta with Respect to 2% BAU Scenario									
2% BAU (LL)	(59,698)	(0)	59,699	(45,723)	(12,919)	59,699	(4,372)	(8,966)	(8,589)	(4.7)
2% BAU (LL, LG)	(90,412)	(0)	90,412	(7,073)	(82,364)	90,412	(6,100)	(16,197)	(13,911)	(10.8)
2% BAU (LG)	(29,852)	(0)	29,852	29,071	(57,433)	29,852	(2,129)	(7,760)	(5,133)	(5.5)
2% BAU (LG, C)	(59,449)	0	59,449	140,102	(195,845)	59,449	19,292	23,328	29,597	31.9
2% BAU (PF)	(213)	(0)	213	199	956	213	(8)	158	848	0.9

RE: Renewable Energy

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Comparison of Low Load Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (LL)	845,300	17,217	107,089	146,302	408,699	107,089	36,099	61,057	62,358	71.8	
	Delta with Respect to 2% BAU (LL) Scenario										Relative to 2% BAU (LL)
14% RPS (LL)	(76,524)	105,328	(28,804)	(40,971)	(35,247)	(28,804)	(6,307)	(1,430)	(2,333)	(2.7)	59.9
20% LOBO (LL)	(127,972)	159,638	(31,665)	(43,109)	(81,441)	(31,665)	(9,151)	(8,916)	(9,807)	(11.3)	57.3
30% LOBO (LL)	(245,358)	258,611	(13,252)	(49,052)	(196,297)	(13,252)	(13,843)	(11,409)	(8,069)	(12.5)	53.5

RE: Renewable Energy

Comparison of Low Load + Low Natural Gas Prices Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (LL, LG)	814,586	17,216	137,802	184,952	339,254	137,802	34,370	53,826	57,036	65.7	
	Delta with Respect to 2% BAU (LL, LG) Scenario										Relative to 2% BAU (LL, LG)
14% RPS (LL, LG)	(73,278)	105,717	(32,439)	(37,527)	(35,426)	(32,439)	(5,888)	(1,585)	(2,982)	(3.4)	55.7
20% LOBO (LL, LG)	(129,955)	161,216	(31,262)	(47,615)	(79,887)	(31,262)	(8,916)	(8,277)	(9,495)	(10.9)	55.3
30% LOBO (LL, LG)	(241,424)	259,642	(18,218)	(65,977)	(175,857)	(18,218)	(13,592)	(10,826)	(8,691)	(12.9)	52.4

RE: Renewable Energy

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Comparison of Low Natural Gas Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (LG)	875,145	17,217	77,243	221,096	364,185	77,243	38,341	62,263	65,814	70.9	
	Delta with Respect to 2% BAU (LG) Scenario										Relative to 2% BAU (LG)
14% RPS (LG)	(75,727)	105,806	(30,080)	(39,785)	(35,847)	(30,080)	(6,239)	(2,981)	(4,197)	(4.5)	59.0
20% LOBO (LG)	(132,052)	161,906	(29,855)	(52,492)	(77,874)	(29,855)	(9,462)	(10,347)	(11,287)	(12.2)	58.4
30% LOBO (LG)	(245,446)	260,271	(14,825)	(76,131)	(170,133)	(14,825)	(14,249)	(13,294)	(10,658)	(14.4)	54.7

RE: Renewable Energy

Comparison of Low Natural Gas Prices + High Carbon Price Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (LG, C)	845,548	17,217	106,839	332,128	225,773	106,839	59,763	93,352	100,545	108.4	
	Delta with Respect to 2% BAU (LG, C) Scenario										Relative to 2% BAU (LG, C)
14% RPS (LG, C)	(84,213)	105,928	(21,715)	(23,519)	(63,182)	(21,715)	(9,383)	(1,878)	(2,827)	(3.0)	88.6
20% LOBO (LG, C)	(142,725)	163,088	(20,363)	(37,703)	(106,978)	(20,363)	(14,844)	(10,495)	(10,251)	(11.1)	91.0
30% LOBO (LG, C)	(215,763)	260,898	(45,135)	(74,370)	(145,102)	(45,135)	(23,246)	(13,412)	(11,537)	(17.1)	89.1

RE: Renewable Energy

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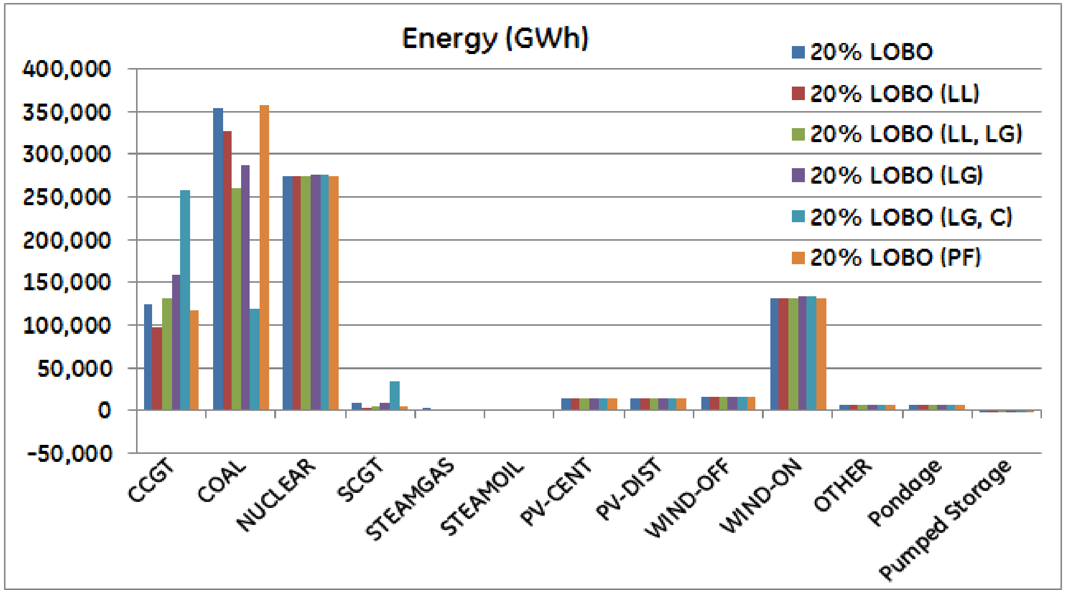
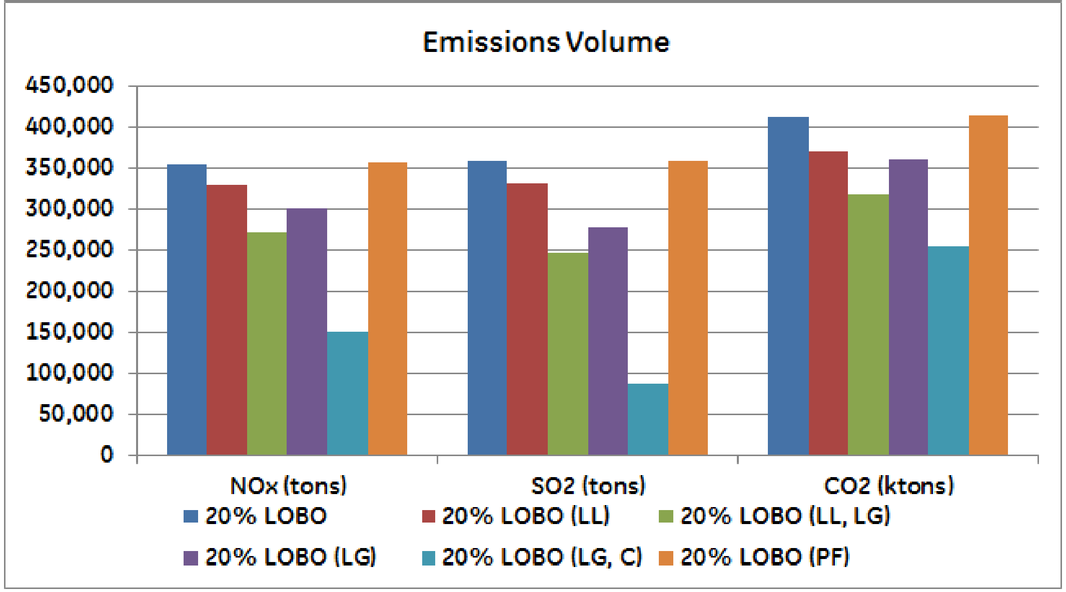
Comparison of Perfect Forecast Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (PF)	904,785	17,217	47,603	192,225	422,573	47,603	40,462	70,182	71,795	77.4	
	Delta with Respect to 2% BAU (PF) Scenario										Relative to 2% BAU (PF)
14% RPS (PF)	(80,147)	105,465	(25,318)	(49,251)	(30,518)	(25,318)	(6,993)	(7,353)	(7,768)	(8.4)	66.3
20% LOBO (PF)	(123,699)	160,875	(37,176)	(53,318)	(67,577)	(37,176)	(9,925)	(11,456)	(12,598)	(13.6)	61.7
30% LOBO (PF)	(236,280)	260,139	(23,859)	(66,287)	(170,096)	(23,859)	(14,956)	(14,413)	(12,060)	(16.1)	57.5

RE: Renewable Energy

Sensitivity Operational Impacts (20% LOBO)



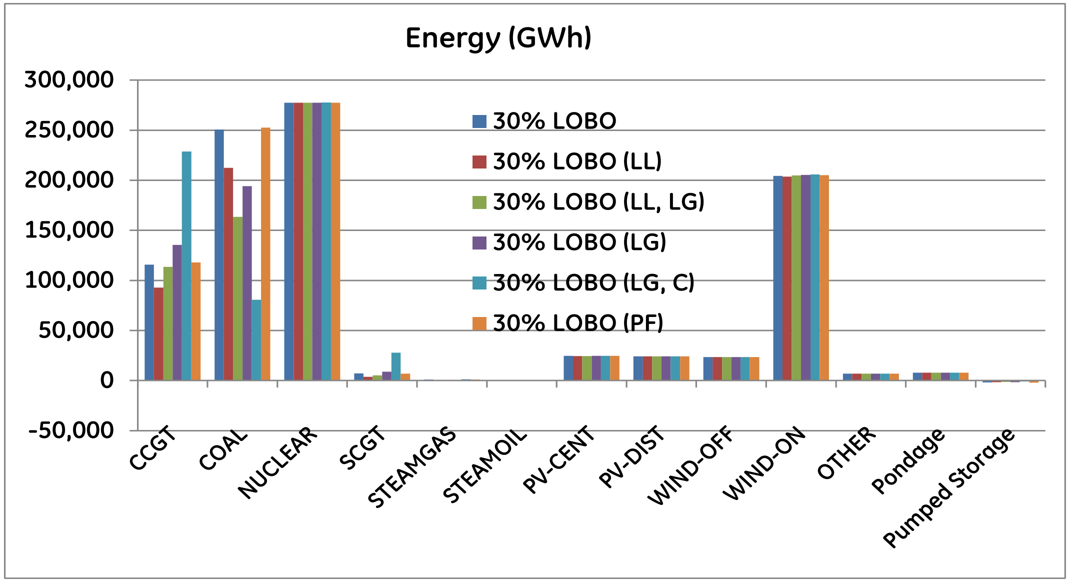


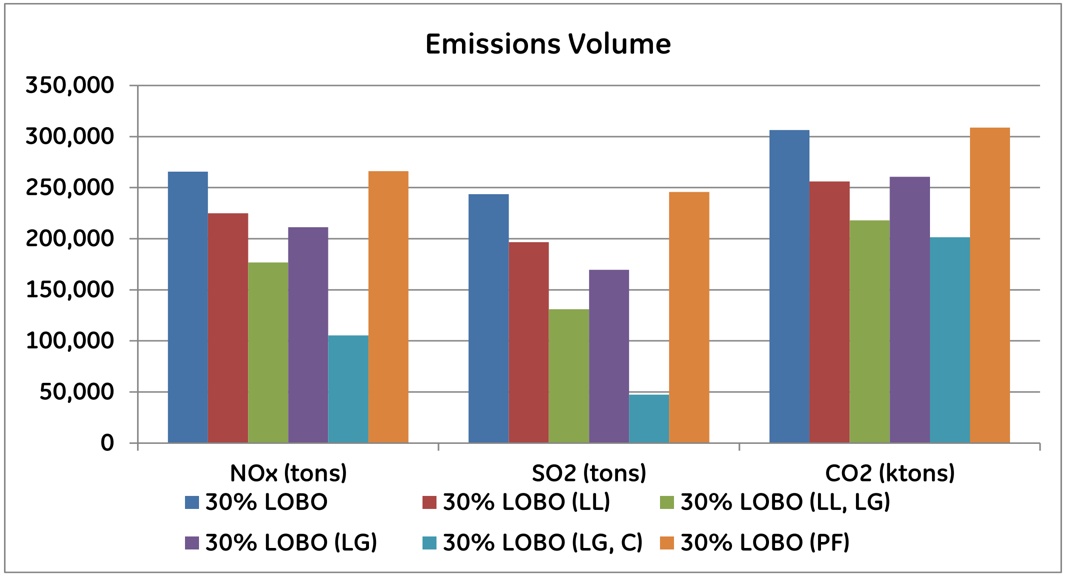
- Low Gas/Carbon has the largest coal displacement.
- In Perfect Forecast case, SCGT operation decreases.
- Impact may be greater in operational (PROBE) analysis.

Sensitivity Economic Impacts (20% LOBO)

PJM Sensitivities	20% LOBO	20% LOBO (LL)	20% LOBO (LL, LG)	20% LOBO (LG)	20% LOBO (LG, C)	20% LOBO (PF)
Production Costs ($M)	30,610	26,947	25,454	28,879	44,919	30,537
Change from Base	0	-3,663	-5,156	-1,731	14,309	-73
Relative Change	0.00%	-13.59%	-20.26%	-5.99%	31.86%	-0.24%
Generator Revenue ($M)	59,178	52,141	45,549	51,916	82,857	58,725
Change from Base	0	-7,037	-13,629	-7,262	23,679	-453
Relative Change	0.00%	-13.50%	-29.92%	-13.99%	28.58%	-0.77%
Costs to Load ($M)	61,341	52,551	47,541	54,528	90,294	59,197
Change from Base	0	-8,790	-13,800	-6,814	28,952	-2,144
Relative Change	0.00%	-16.73%	-29.03%	-12.50%	32.06%	-3.62%
Load Wtd LMP ($/MWh)	66.1	60.5	54.7	58.8	97.3	63.8
Change from Base	0.00	-5.62	-11.39	-7.35	31.21	-2.31
Relative Change	0.00%	-9.29%	-20.81%	-12.50%	32.06%	-3.63%

Sensitivity Operational Impacts (30% LOBO)





Sensitivity Economic Impacts (30% LOBO)

PJM Sensitivities	30% LOBO	30% LOBO (LL)	30% LOBO (LL, LG)	30% LOBO (LG)	30% LOBO (LG, C)	30% LOBO (PF)
Production Costs ($M)	25,708	22,255	20,778	24,092	36,517	25,506
Change from Base	0	-3,452	-4,930	-1,615	10,809	-201
Relative Change	0.00%	-15.51%	-23.72%	-6.71%	29.60%	-0.79%
Generator Revenue ($M)	56,860	49,648	43,001	48,969	79,940	55,769
Change from Base	0	-7,212	-13,859	-7,891	23,079	-1,091
Relative Change	0.00%	-14.53%	-32.23%	-16.11%	28.87%	-1.96%
Costs to Load ($M)	61,635	54,289	48,345	55,156	89,008	59,735
Change from Base	0	-7,346	-13,291	-6,479	27,372	-1,900
Relative Change	0.00%	-13.53%	-27.49%	-11.75%	30.75%	-3.18%
Load Wtd LMP ($/MWh)	63.2	59.3	52.8	56.6	91.3	61.3
Change from Base	0.00	-3.94	-10.43	-6.65	28.07	-1.95
Relative Change	0.00%	-6.65%	-19.76%	-11.75%	30.75%	-3.19%

Sensitivity Analysis Key Findings

- Sensitivity analysis key findings are:
  - Low Load caused generation displacement of both Coal and Gas generation.
  - Low Natural Gas caused an increase in Gas generation and a decrease in Coal generation.
  - Low Natural Gas & Carbon caused a significant increase in CCGT operation and a decrease in Coal.
  - Low Load & Low Natural Gas had minimal impact on CCGT operation , because of offsetting impacts and Coal had an additive impact.
  - Perfect renewable forecast appeared to result in relatively small decrease in economic variables compared to the other sensitivities.

Impact of Sensitivities on Production Costs

	Base	(LL)	(LL, LG)	(LG)	(LG, C)	(PF)
Production Costs($M)						
2% BAU	40,470	36,099	34,370	38,341	59,763	40,462
14% RPS	33,719	29,791	28,482	32,102	50,380	33,470
20% LOBO	30,610	26,947	25,454	28,879	44,919	30,537
30% LOBO	25,708	22,255	20,778	24,092	36,517	25,506
Delta Relative to 2% BAU						
2% BAU	0	0	0	0	0	0
14% RPS	-6,751	-6,307	-5,888	-6,239	-9,383	-6,993
20% LOBO	-9,860	-9,151	-8,916	-9,462	-14,844	-9,925
30% LOBO	-14,763	-13,843	-13,592	-14,249	-23,246	-14,956
Compared to the Base Case						
2% BAU	-	-	-	-	-	-
14% RPS	-	-6.6%	-12.8%	-7.6%	39.0%	3.6%
20% LOBO	-	-7.2%	-9.6%	-4.0%	50.5%	0.7%
30% LOBO	-	-6.2%	-7.9%	-3.5%	57.5%	1.3%

- Production cost savings from renewable energy can vary significantly depending on assumptions about fuel prices, load growth, and emission costs.
- For example, compared to the base scenario, production cost savings in the 14% RPS scenario were 12.8% lower for the Low Load / Low Gas sensitivity and 39% higher for the Low Gas / High Carbon sensitivity.

Capacity Valuation Analysis (GE) [15 Minutes]

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Capacity Valuation Analysis Approach

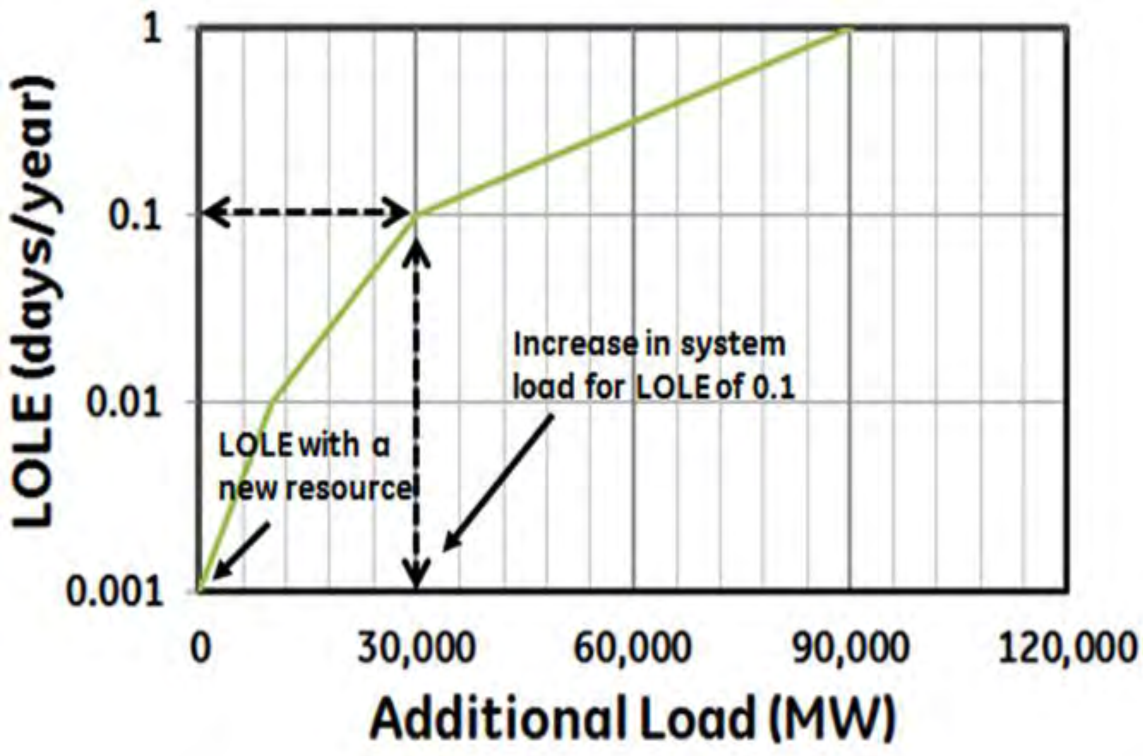
- Wind Capacity Valuation involved loss of load expectation (LOLE) calculations for the study footprint using the GE's Multi-Area Reliability Simulation (GE MARS) model.
  - The LOLE analysis determined the Effective Load Carrying Capability (ELCC) of the incremental wind and solar generation additions.
  - The analysis quantified the impact of wind and solar generation on overall reliability measures, as well as the capacity values of the wind and solar generation resources based on the ELCC methodology.
  - Three year load and resource (wind/solar) data is used (2004, 2005, and 2006).
  - Artificial variability is introduced in each year's resource data by allowing GE MARS to select the current day profile from +/- 7 day window.
    - This is being used as a substitute in absence of having many years of synchronized load/resource data.
  - The ELCC of a resource is the average ELCC across the three years (in a particular scenario).

Effective Load Carrying Capability of a Resource

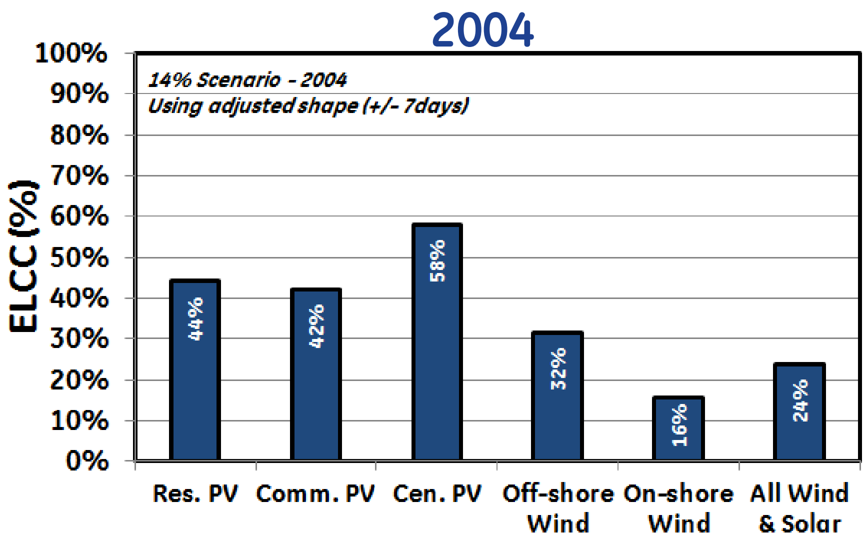
- The ELCC of a resource is defined as the increase in peak load that will give the same system reliability as the original system without the resource.

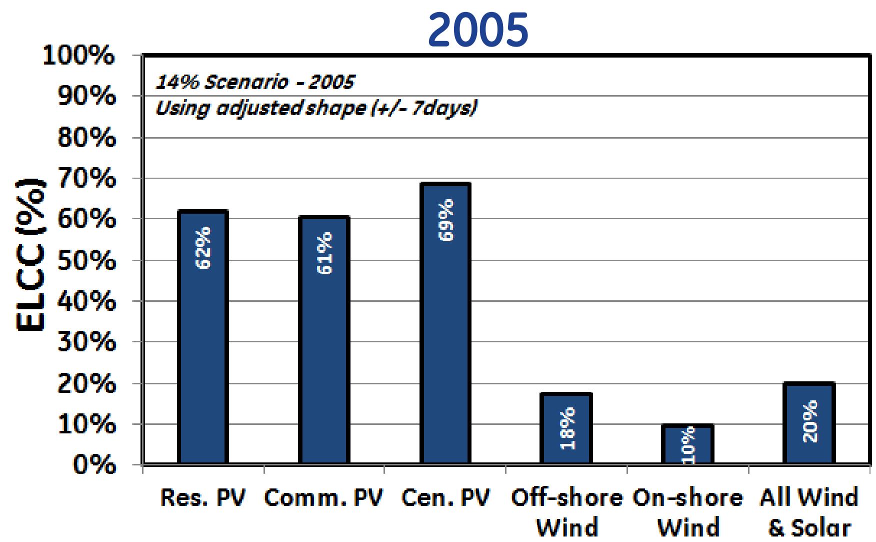
- Figure to the right shows that the addition of a block of renewables allowed the peak load to increase by 30,000 MW in order to bring the system reliability back to the original design criteria of 0.1 days/year.

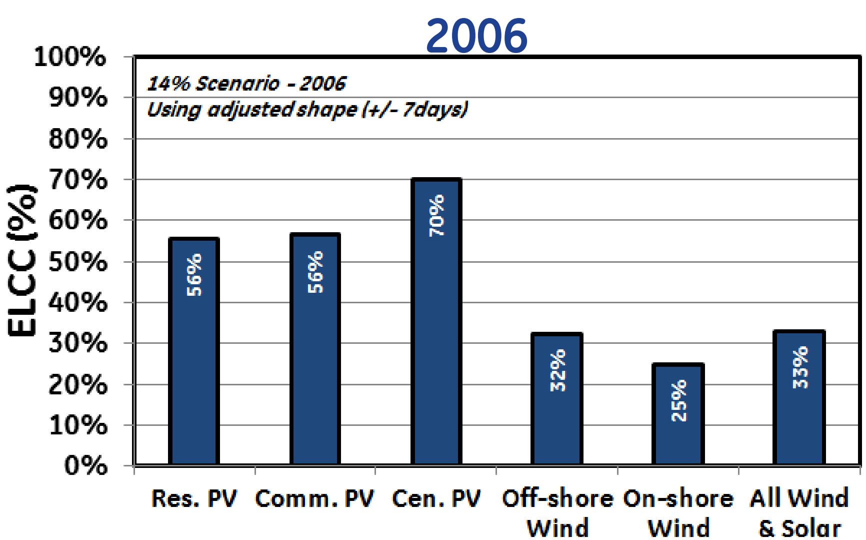
- If this was for the addition of 100,000 MW of renewable capacity the average ELCC would be 30% (i.e., 30,000 / 100,000).



RPS 14% Scenario







- ELCC of a resource is the average of the three years → shown on next slide

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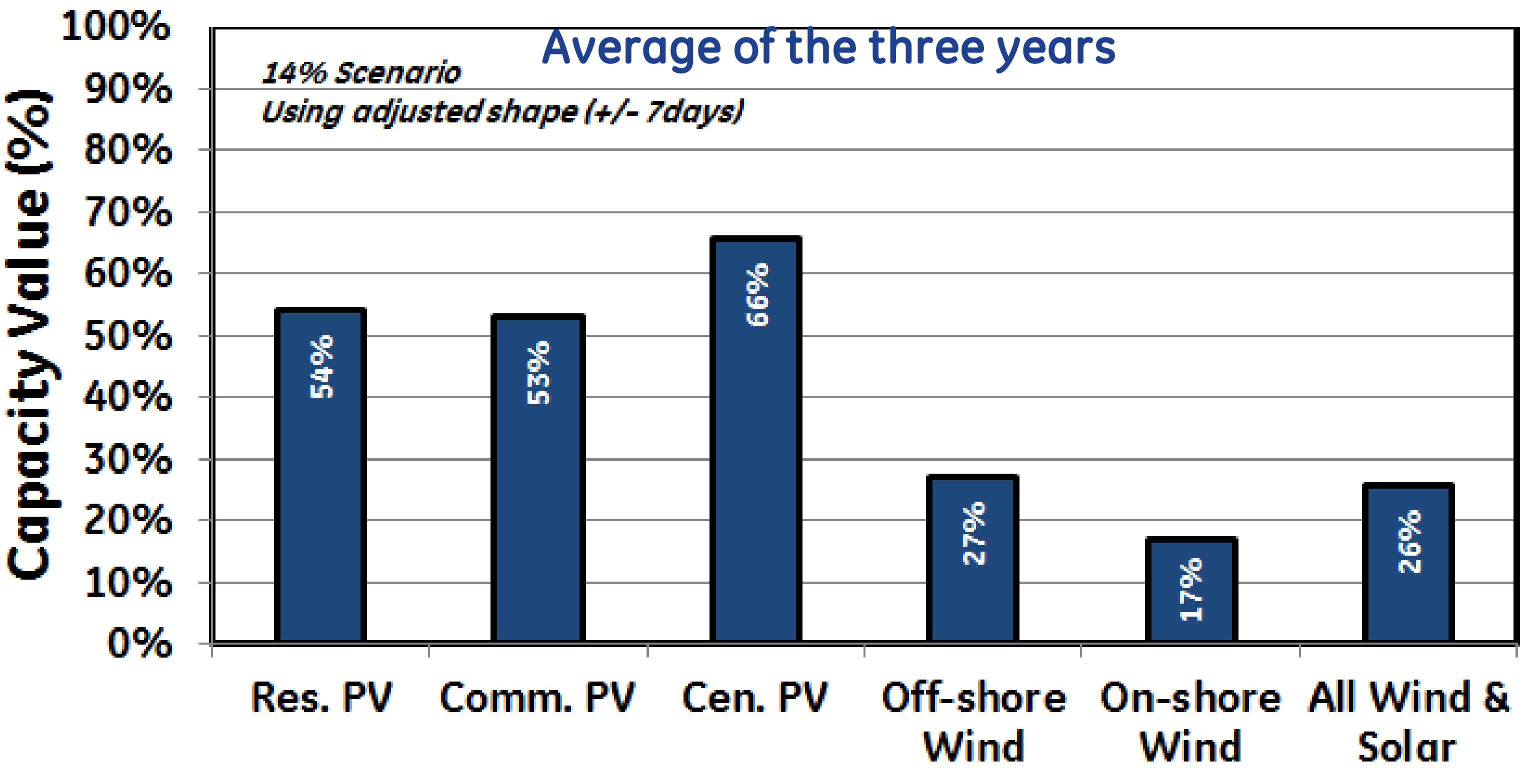
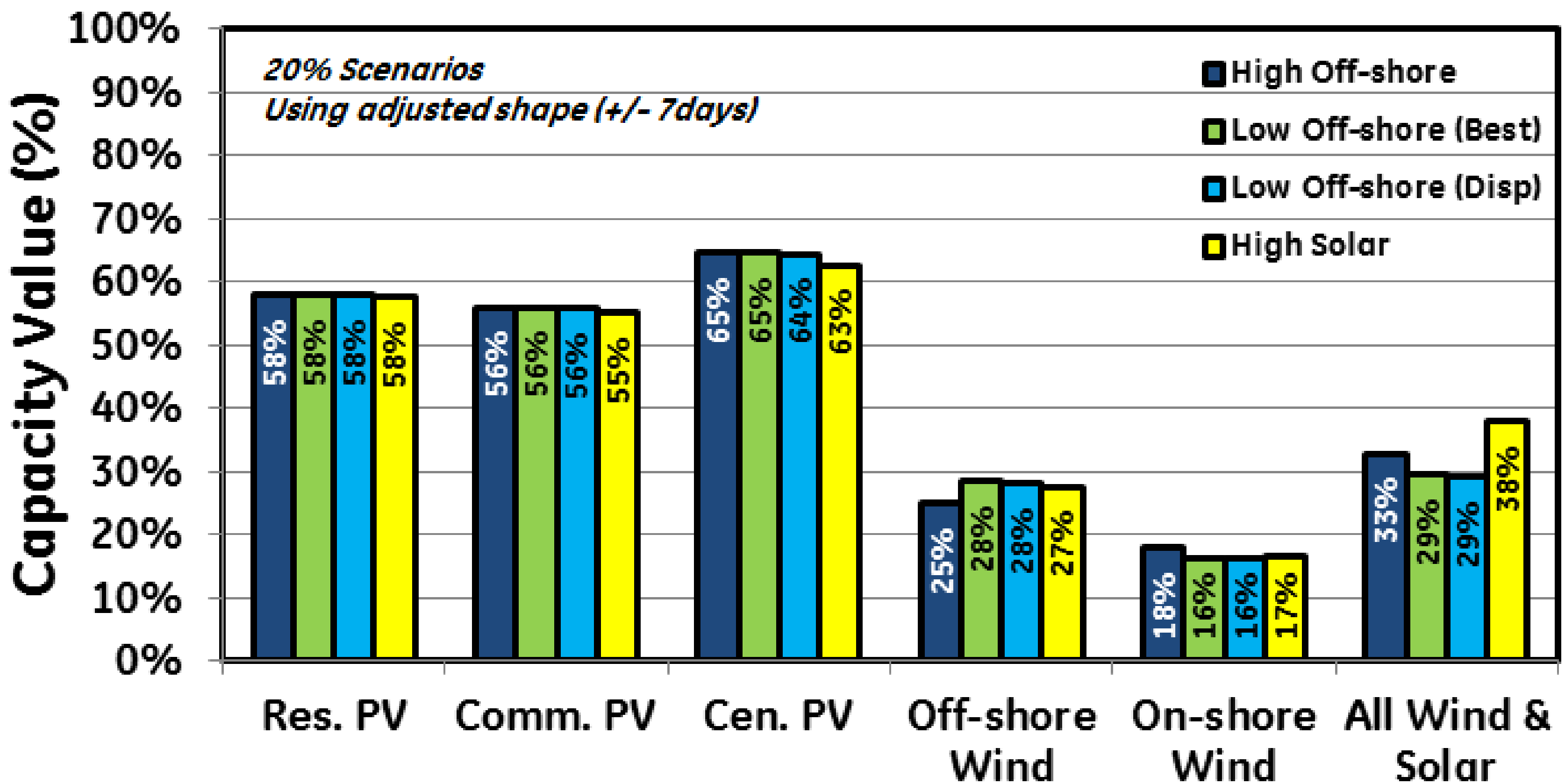
RPS 14% Scenario



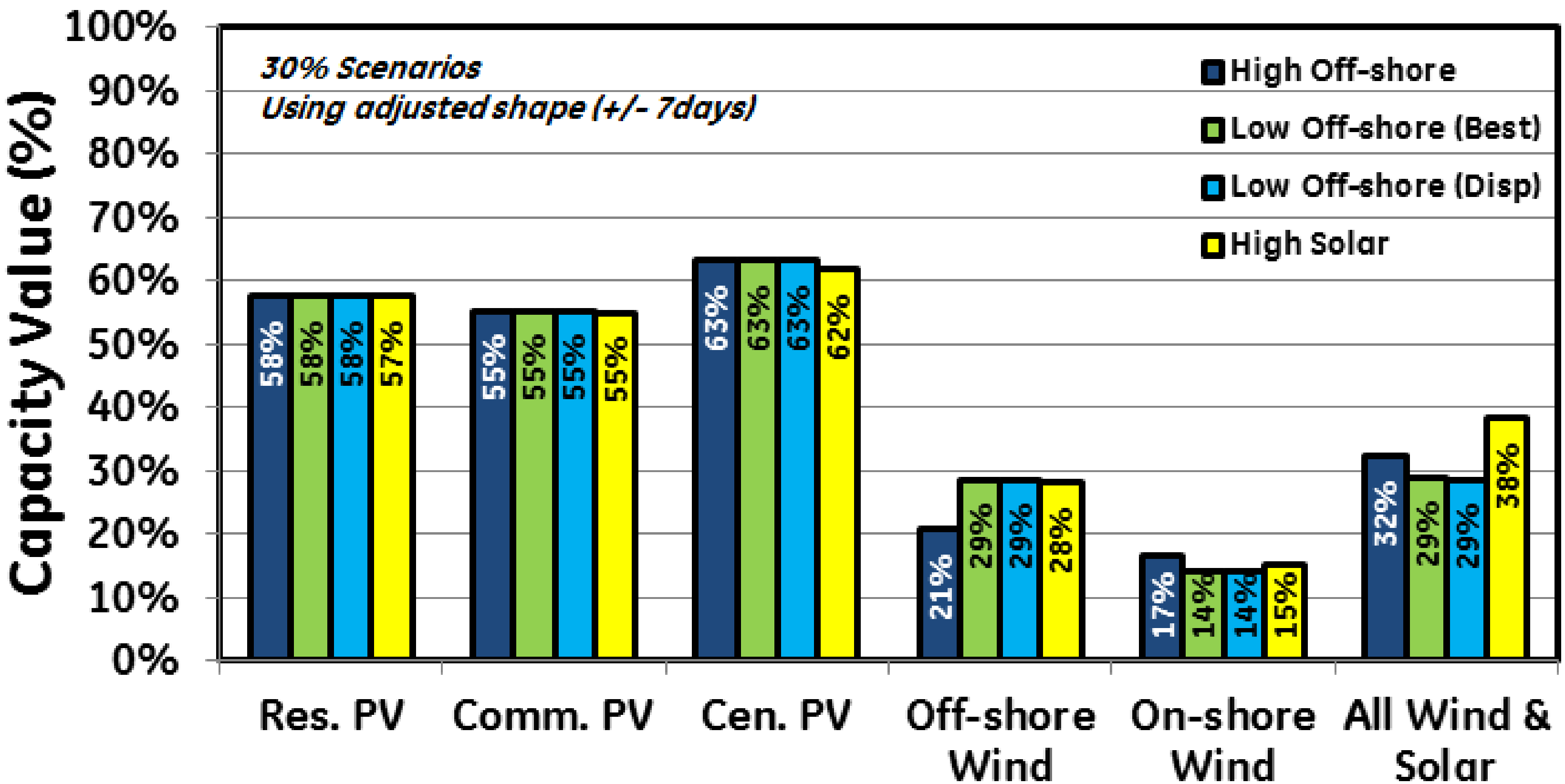
The average ELCC takes into account the year-to-year variation in load/resource data, and provides a more stable result.

20% Scenarios



- ELCC of distribution-connected Solar PV is between 55-58%
- ELCC of Central PV is between 63-65%
  - ELCC drops in the "High Solar" scenario due to saturation
- ELCC of Off-shore Wind is between 25-28%
  - ELCC in "High Off-shore" scenario is low due to saturation
- ELCC of On-shore Wind is between 16-18%

30% Scenarios



- ELCC of the resources is similar to the 20% scenarios
- Drop in ELCC values in some sub-scenarios is mainly due to saturation effect
    - e.g., ELCC of Off-shore Wind drops to 21% from 25% in the “High Off-shore” scenario

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Key Findings: Range of ELCC Values of Different Resources in 20% and 30% Scenarios

Resource	ELCC (%)	PJM Manual 21 (Avg. Cap Factor)
Residential PV	57% - 58%	51%
Commercial PV	55% - 56%	49%
Central PV	62% - 66%	62% - 63%
Offshore Wind	21% - 29%	31% - 34%
Onshore Wind	14% - 18%	24% - 26%

- The wind profiles used in the study assumed advanced turbine design (100 Meter Hub / 2.5-3.0 MW) which are emerging products being adopted, and therefore, the values reported here would be slightly higher than what has been historically observed in PJM (80 Meter Hub / 1.5 MW).
- However, the study values and the PJM values are both based on the same hourly generation profiles.

Transmission Overlay Analysis (PowerGEM) [15 Minutes]

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Transmission Analysis Objective & Approach

- The purpose of this phase of the study was for PowerGEM to create a transmission overlay that resolved the most significant reliability and congestion issues for each renewable scenario.
- The overlay was developed based on two separate drivers.
  - First a transmission overlay was created to resolve any reliability issues caused by the addition of the renewable resources.
  - A congestion study was then performed using this overlay to determine if any areas of the PJM system had significant congestion.
  - An additional transmission overlay was then created to address any flowgates resulting in congestion greater than a certain threshold.
  - The final transmission overlay was the combination of the reliability driven and congestion driven overlays for each scenario.

Transmission Perspective …

- While the transmission overlays resolved the most significant reliability and congestion issues for each scenario, some potentially significant transmission costs were not within the scope of this study. For example:
  - Generator interconnection costs (wind and solar units were located at nearest EHV bus).
  - Upgrades to resolve overloads at voltage levels below 230kV.
  - Upgrades needed to resolve voltage violations.
- Note also there is still significant congestion remaining in some scenarios (up to $6.3B/year).
- Criteria for Transmission Overlay:
  - Simple to calculate and easy to implement criteria agreed jointly by PJM and GE: Reduce congestion to a level where the difference between the highest generator LMP and the lowest generator LMP is less than or equal to $5/MWh.

Transmission Overlay Process
Example of 20% LOBO Scenario

Transmission Constraints

Dresden – Elwood 345 kV
Brokaw - Pontiac 345 kV
Quad - Sub 91 345 kV
Plano 765/345 kV
Quad - Rock Cities 345 kV
Kanawha River – Matt Funk 345 kV
E. Frankfort – Crete 345 kV

Transmission Overlay for 20% LOBO

Transmission Overlay Due to Reliability
2nd Dresden – Elwood 345 kV
2nd Brokaw - Pontiac 345 kV
Transmission Overlay Due to Congestion
2nd Quad - Sub 91 345 kV
2nd Quad - Rock Cities 345 kV
Reconductor Kanawha R. – M. Funk 345 kV
2nd E. Frankfort – Crete 345 kV
New Plano 765/345 kV

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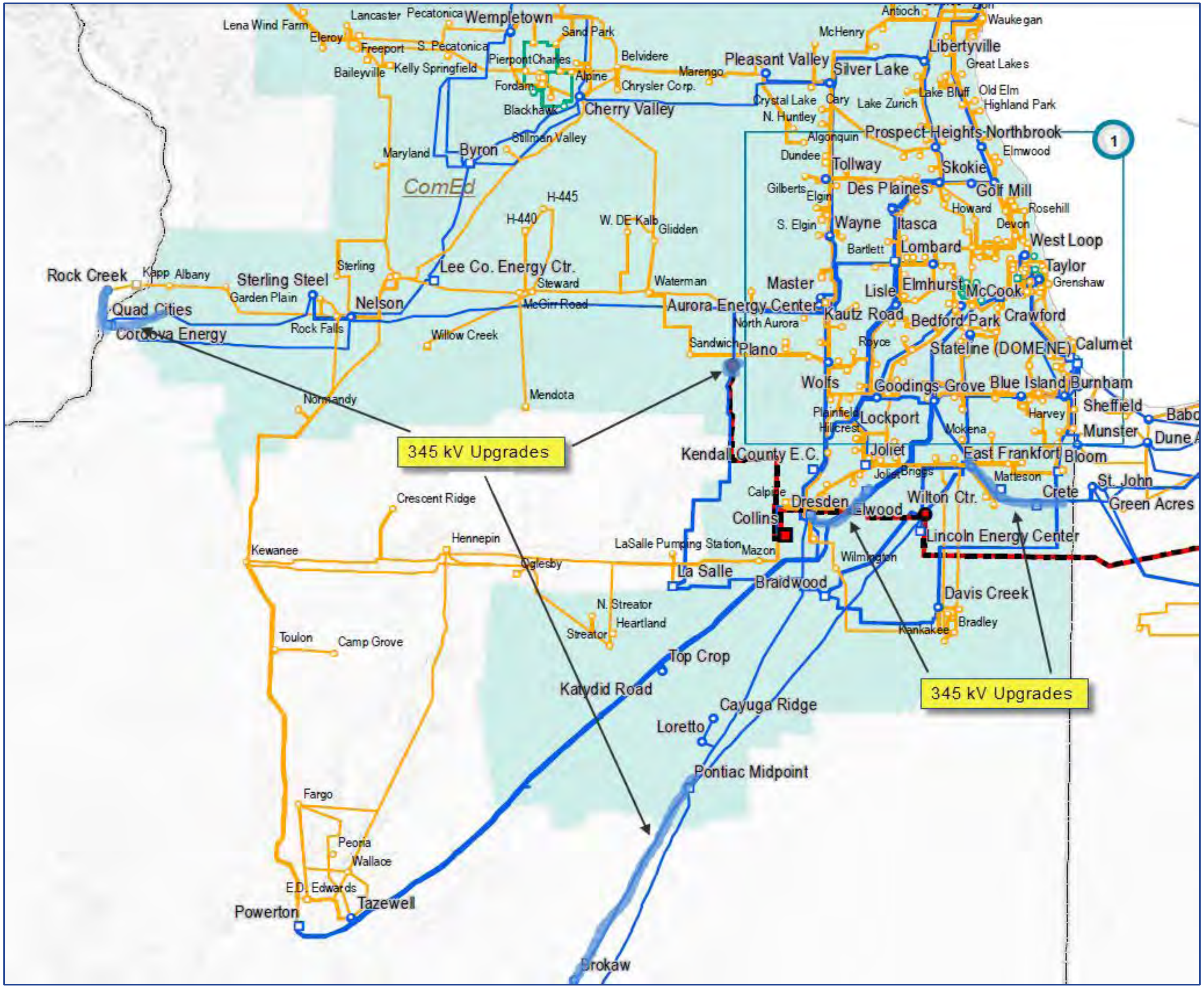
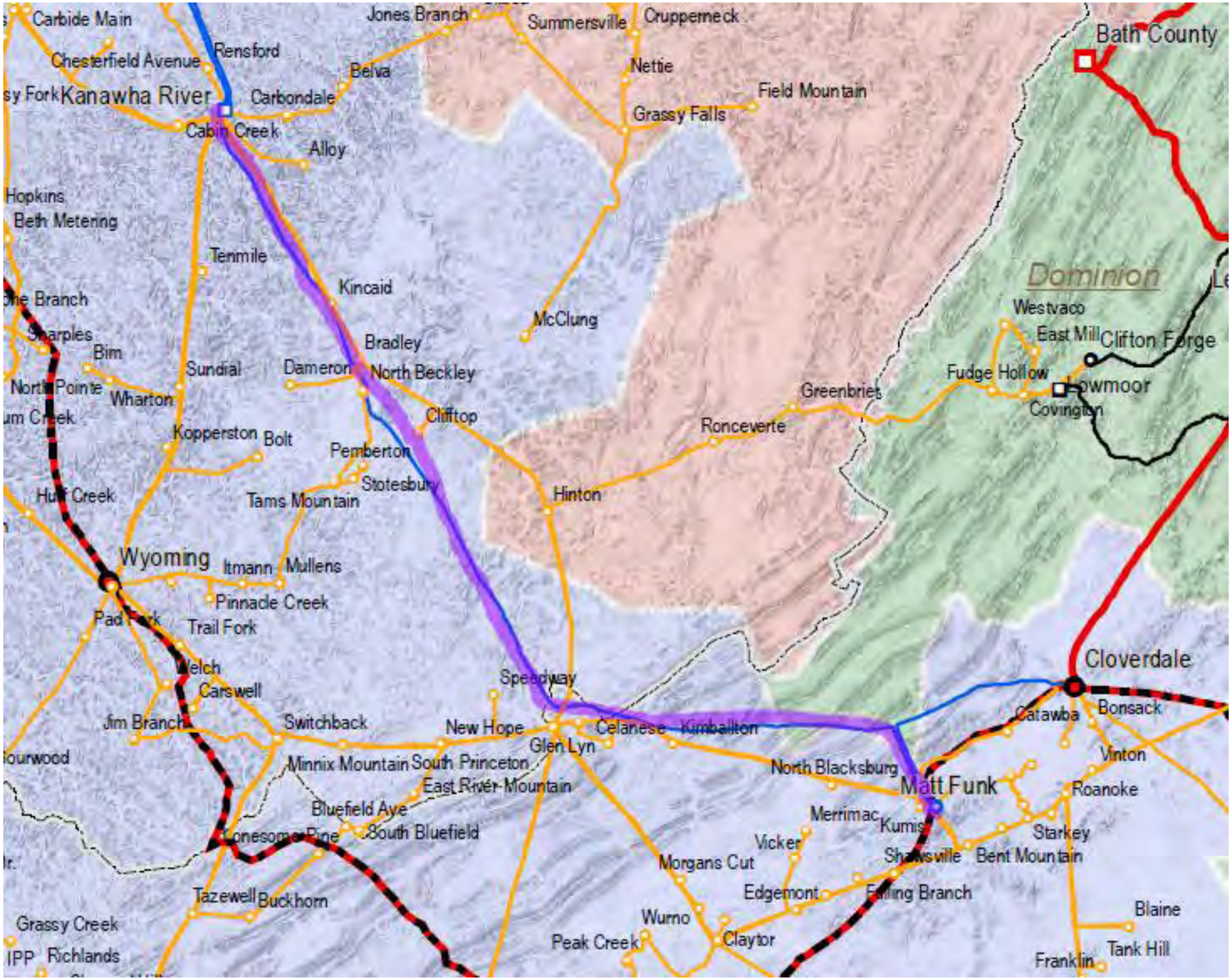
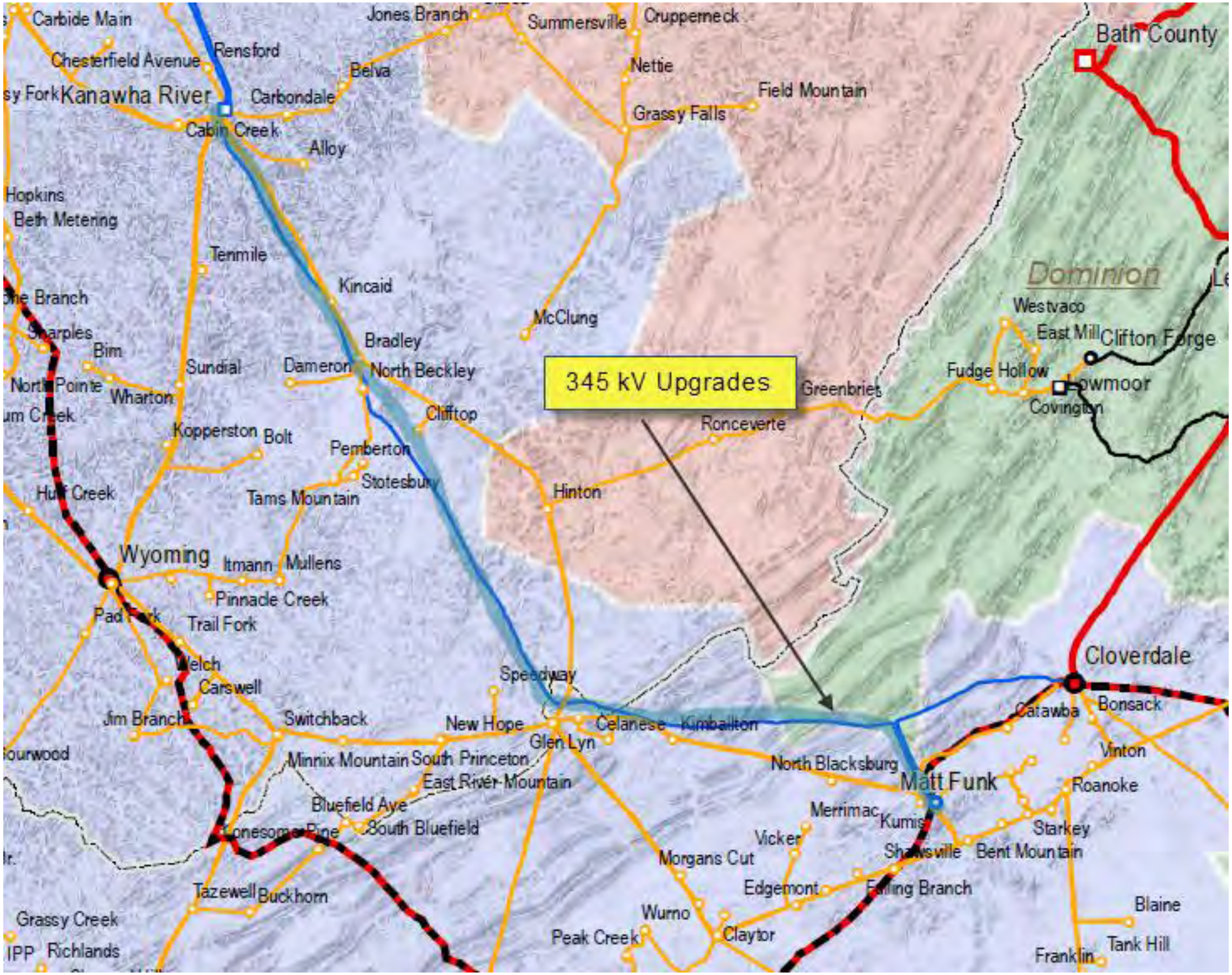
20% LOBO Transmission Overlay - ComED



20% LOBO Transmission Constraints - AEP



20% LOBO Transmission Overlay - AEP



Summary of New Transmission Lines and Upgrades for the Study

Scenario	765 kV New Lines (Miles)	765 kV Upgrades (Miles)	500 kV New Lines (Miles)	500 kV Upgrades (Miles)	345 kV New Lines (Miles)	345 kV Upgrades (Miles)	230 kV New Lines (Miles)	230 kV Upgrades (Miles)	Total (Miles)	Total Cost (Billion)	Total Congestion Cost (Billion)
2% BAU	0	0	0	0	0	0	0	0	0	$0	$1.9
14% RPS	260	0	42	61	352	35	0	4	754	$3.7	$4.0
20% Low Offshore Best Onshore	260	0	42	61	416	122	0	4	905	$4.1	$4.0
20% Low Offshore Dispersed Onshore	260	0	42	61	373	35	0	49	820	$3.8	$4.9
20% High Offshore Best Onshore	260	0	112	61	363	122	17	4	939	$4.4	$4.3
20% High Solar Best Onshore	260	0	42	61	365	122	0	4	854	$3.9	$3.3
30% Low Offshore Best Onshore	1800	0	42	61	796	129	44	74	2946	$13.7	$5.2
30% Low Offshore Dispersed Onshore	430	0	42	61	384	166	44	55	1182	$5.0	$6.3
30% High Offshore Best Onshore	1220	0	223	105	424	35	14	29	2050	$10.9	$5.3
30% High Solar Best Onshore	1090	0	42	61	386	122	4	4	1709	$8	$5.6

Lunch

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Statistical & Reserve Analysis (EnerNex) [15 Minutes]

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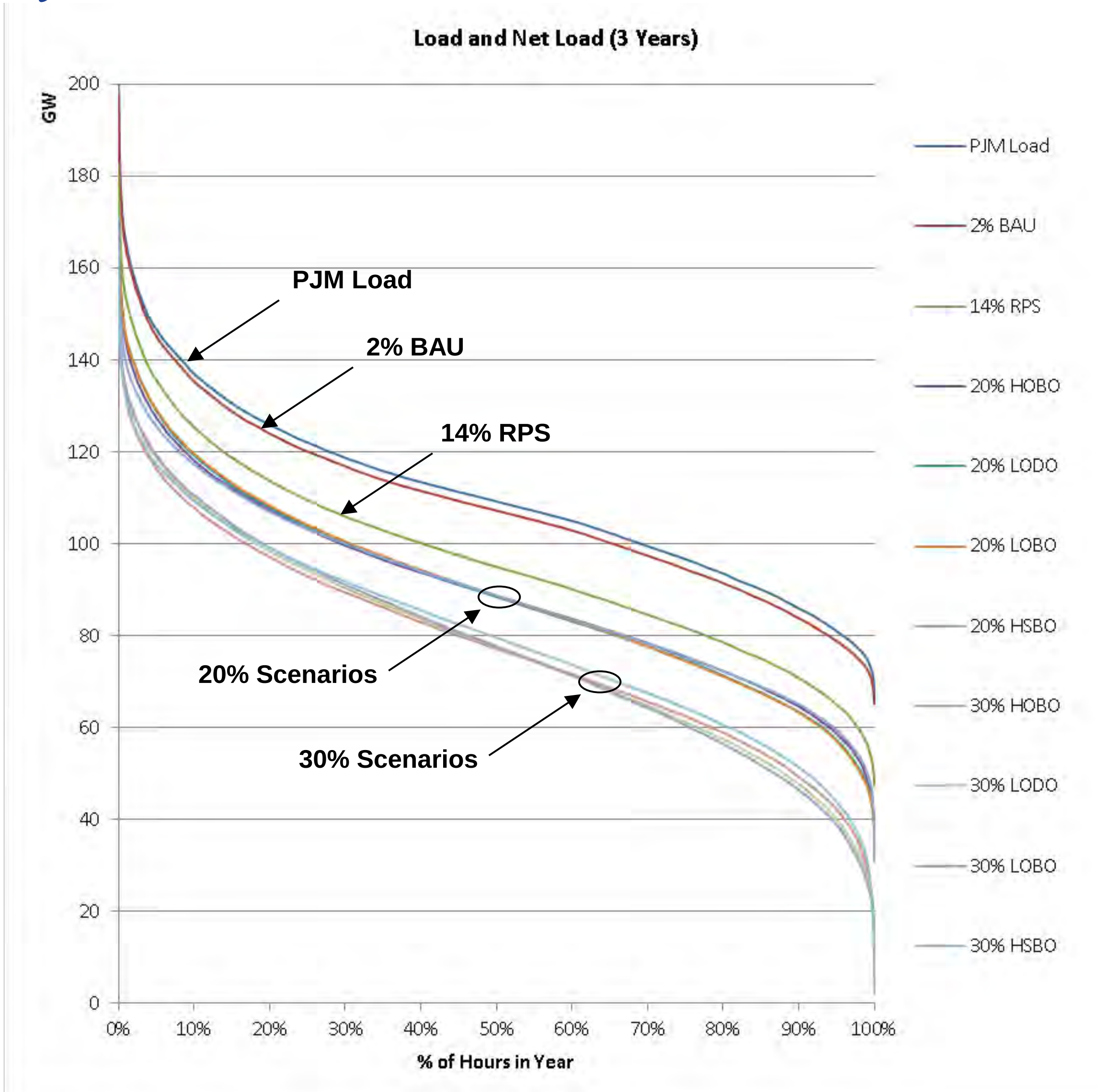
Statistical Analysis Objective

- Statistical Analysis was performed in order to characterize the PJM system load data and renewable resource data.
  - The statistical analysis and characterization of the renewable resources examine the aggregate production i.e. the total generation of all wind and PV sites in each study scenario.
  - PJM provided 5-minute resolution load for the same calendar years as the renewable production data, since system load can be affected by weather conditions and renewable generation is also weather related.
  - The load data was escalated with PJM guidance to make the data sets representative of the future study year.

Duration Curves of PJM Load and Load-Net-Renewables for Study Scenarios

- The right-hand portions of the curves show that in the higher penetration scenarios, renewables serve about half of total system load during low-load periods.

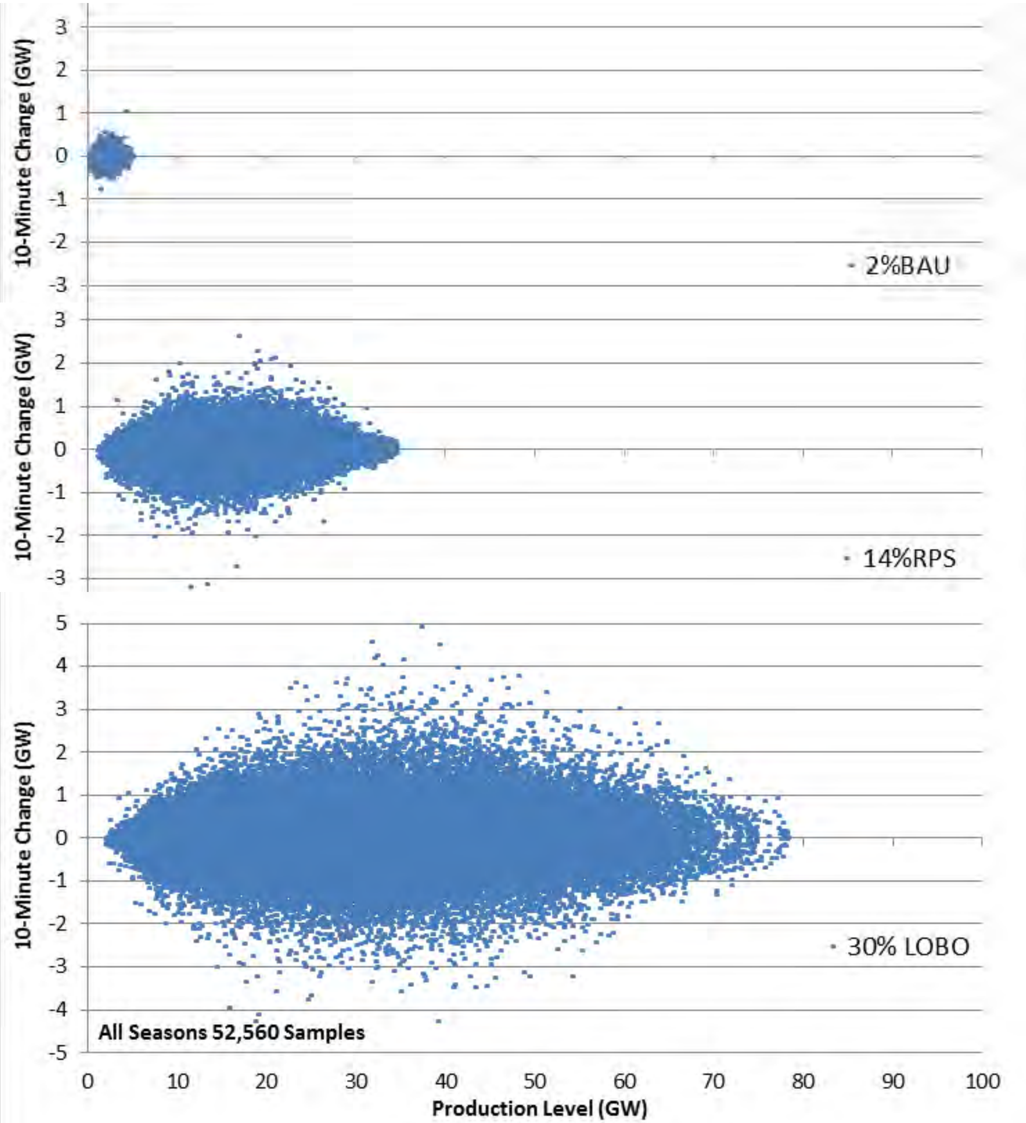


Ten-Minute Wind and Solar Variability as Function of Production Level for Increasing Renewable Penetration

- One significant trend is that the maximum 10-minute variations occur when renewable production is about half of total renewable capacity.

- Variability is lower near maximum production levels, partly because many wind plants are operating above the knee in the wind-power curve where changes in wind speed do not affect electrical power output.

- This characteristic of variability is relevant to the additional Regulation requirement.



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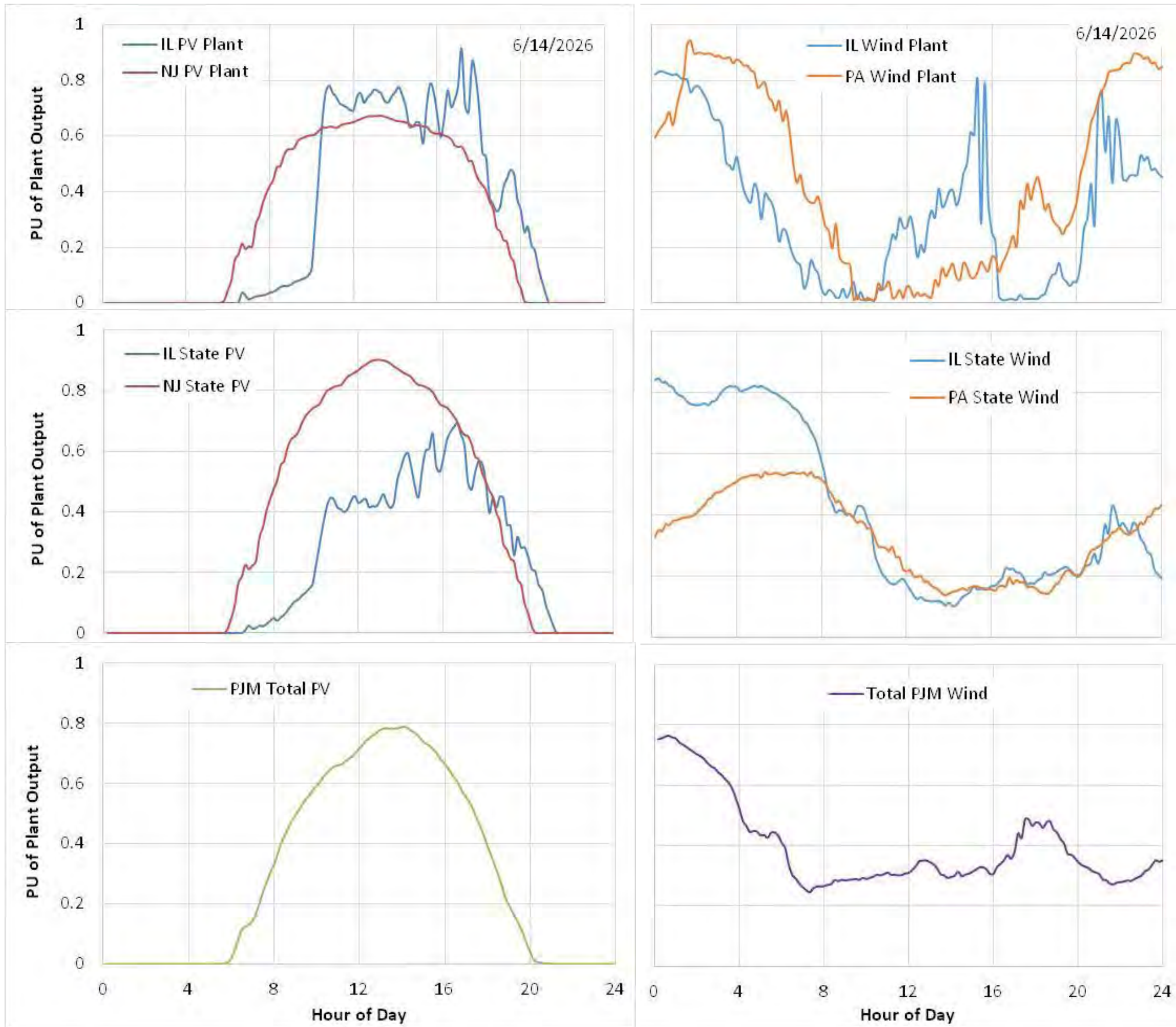
Smoothing of Plant-Level 10-Minute Variability over PJM's Footprint, June 14, 30% LOBO

- Upper traces: High variability associated with individual plants (two solar plants and two wind plants).
- Middle traces: Aggregate profiles for all wind and solar plants within the states of those plants.
- Lower traces: Profiles for all wind plants and solar plants in PJM.



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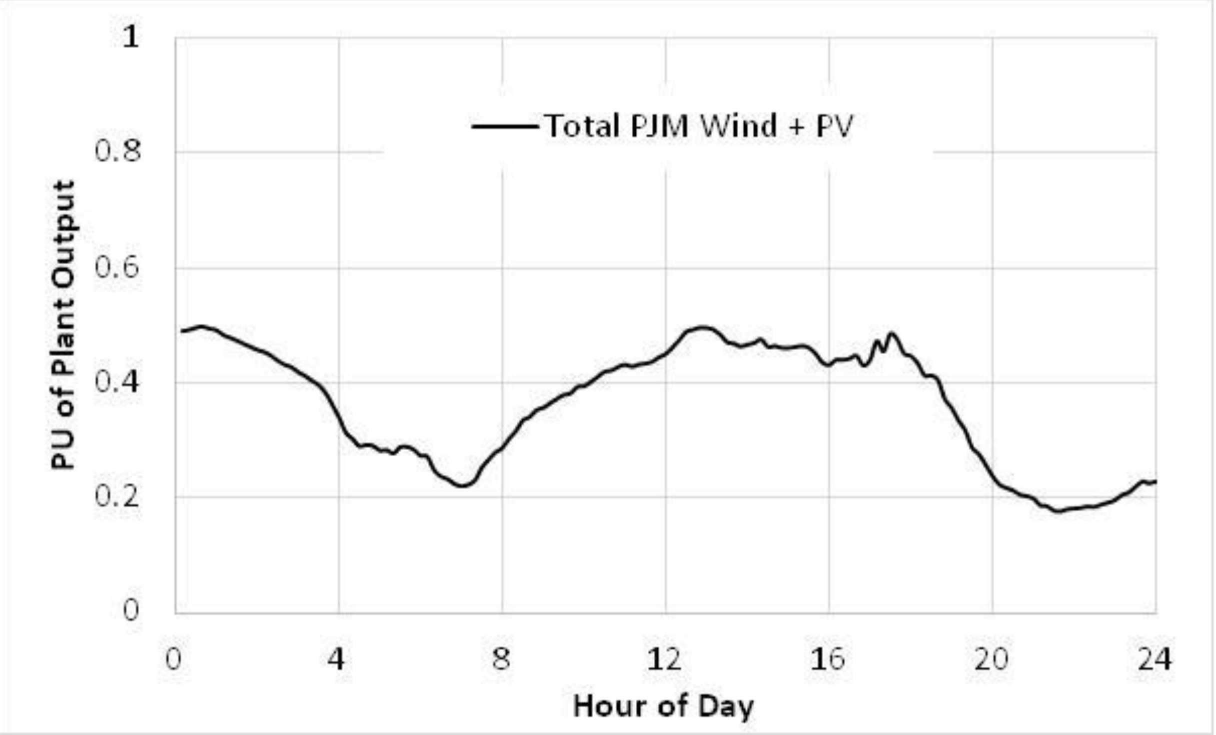
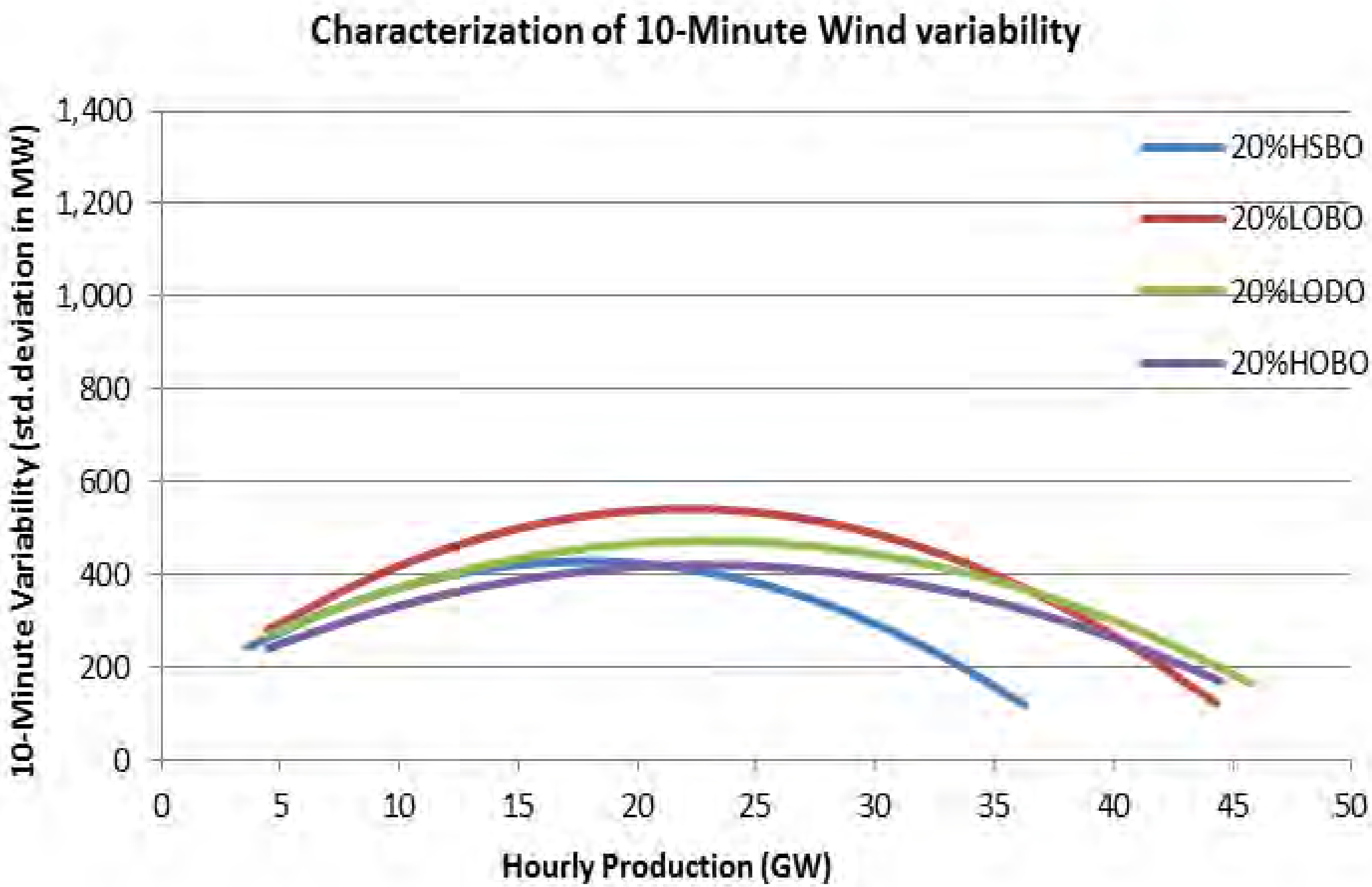
Profiles for the combination of all wind and PV plants in PJM Footprint, June 14, 30% LOBO

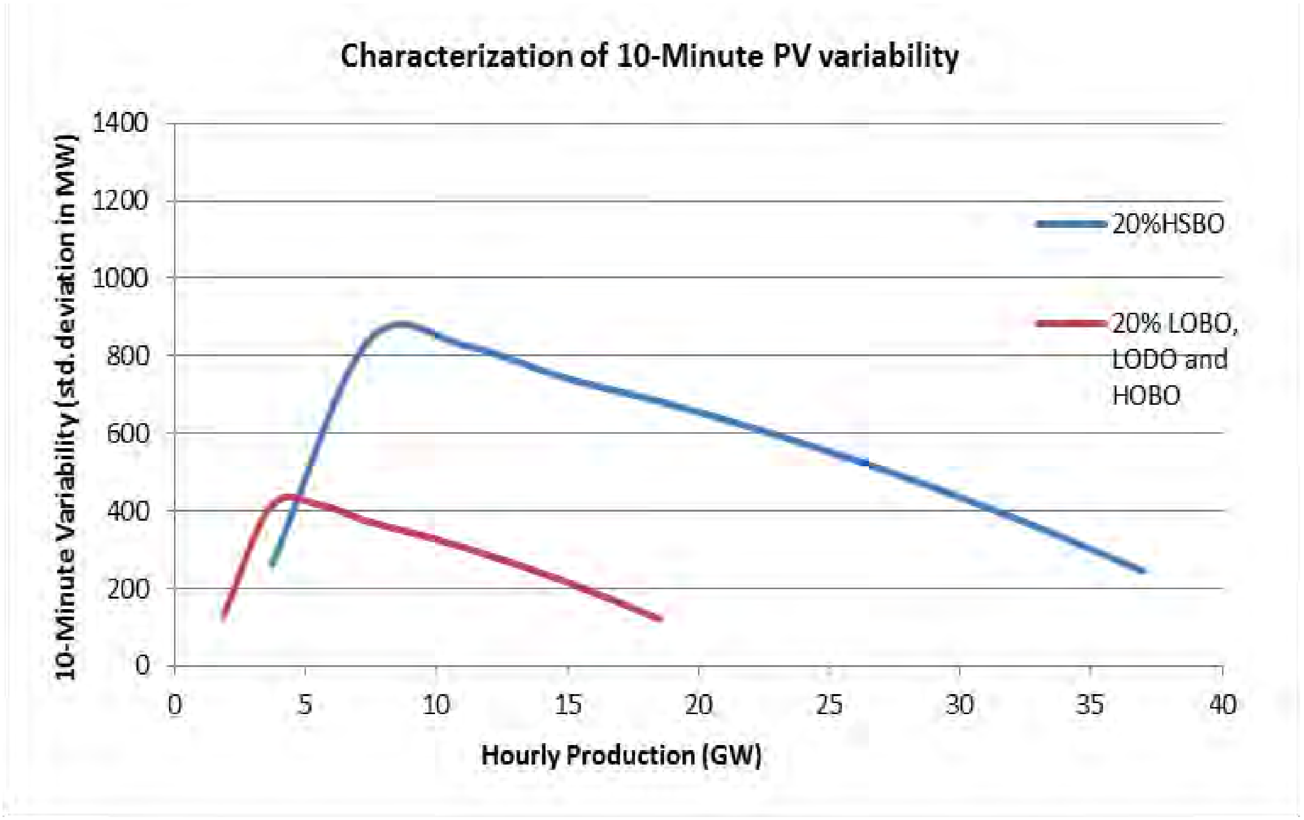
- Short-term variability is dramatically reduced when aggregated across PJM's footprint.
- PJM's large geographic footprint is of significant benefit for integrating wind and solar generation, and greatly reduces the magnitude of variability-related challenges as compared to smaller balancing areas.



Example of 10-Minute Wind Variability for 20% Scenarios



Example of 10-Minute Solar Variability for 20% Scenarios



Statistical Analysis Key Observations & Conclusions

- Statistical analysis was performed to characterize the PJM System load data and renewable resource data.
  - Chronological renewable production data at 10-minute intervals over the calendar years of 2004, 2005 and 2006 were extracted and aggregated by generation type for each scenario.
  - The various statistical characterizations developed to portray the variability and short-term uncertainties of the aggregate wind and PV generation in each scenario are also critical inputs to the analysis of operating reserve impacts.
  - The maximum 10-minute variations occur when renewable production is about half of its total capacity. This characteristic of variability is relevant to the additional Regulation requirement of next section.
  - PJM's large geographic footprint is of significant benefit for integrating wind and solar generation, and greatly reduces the magnitude of variability-related challenges as compared to smaller balancing areas.

Reserve Analysis

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Reserve Analysis Objective

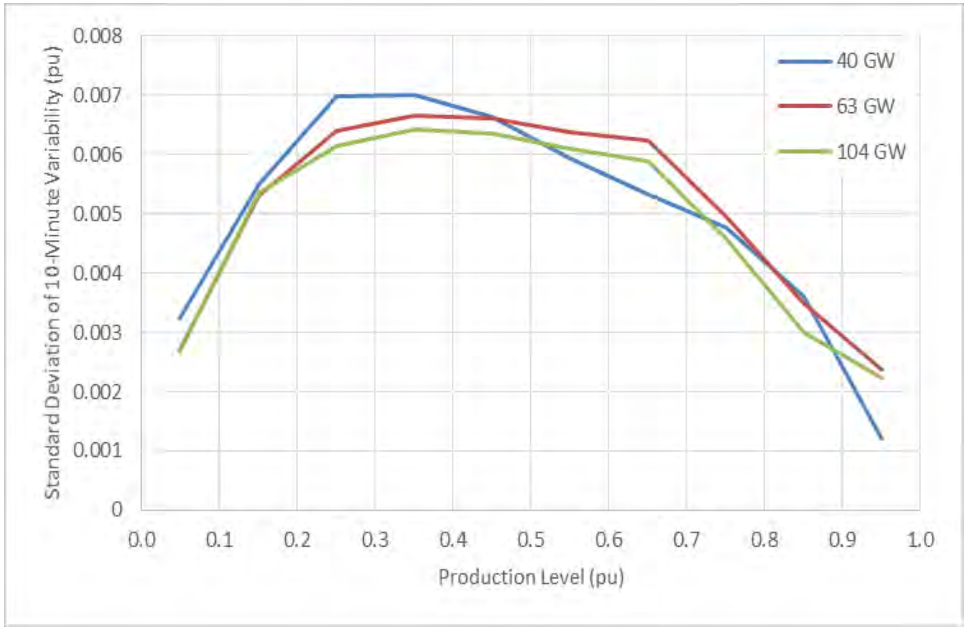
The objective of this task was to evaluate how various levels of wind and PV generation might impact PJM policies and practices for Regulations and Reserves.

- The wind variability adds to the short-term variability of net load (load minus wind), which requires additional Regulation.
- This additional Regulation requirement is above and beyond the current Regulation requirements, since renewable variability should not impinge on the current regulation (or reserve) requirements.

Statistical Analysis for Estimation of Additional Regulation Requirement

- Statistical analysis of wind, PV and load data was employed to determine how much additional regulation capacity would be required to manage renewable variability in each of the study scenarios.
  - Previous studies have established that a statistically high level of confidence for reserve is achieved at about 3 standard of deviation (or σ in industry parlance) of 10-minute renewable variability.
  - i.e., with a reserve margin of 3σ, the chances of a 10-minute wind level drop being greater than 3σ, is highly unlikely.

Hence, the appropriate required regulation is 3 times the standard deviation, which would encompass 99.7% of all variations.



Estimated Regulation Requirements for Each Scenario (All Hours)

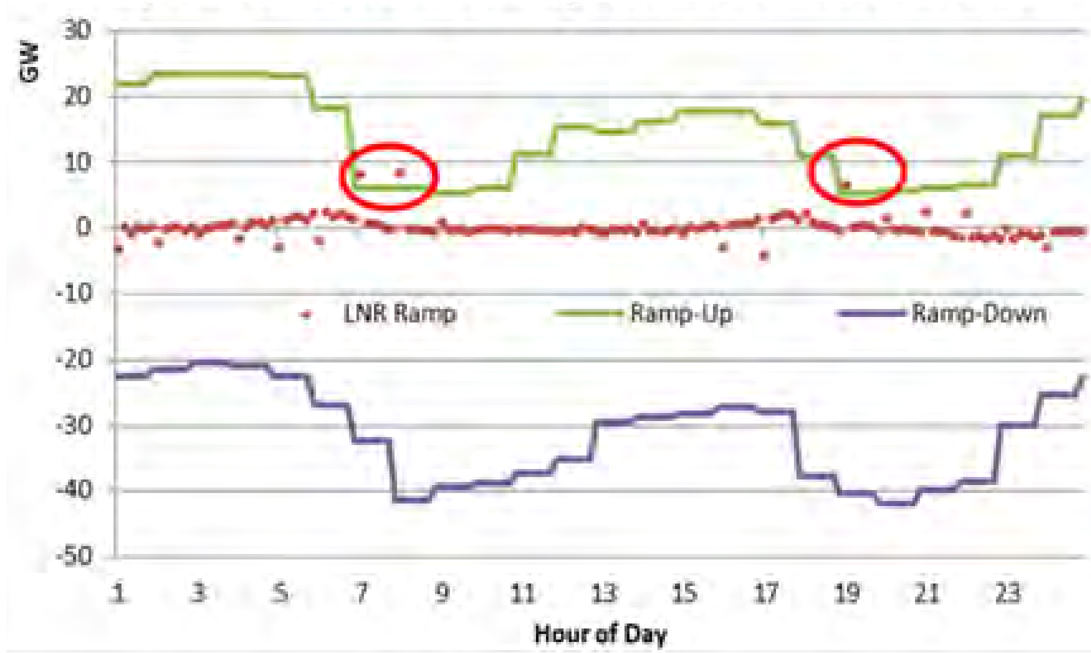
- The amount of additional regulation calculated for each hour depends on
  - The amount of regulation carried for load alone.
    - When more regulation is available, the incremental impact of wind and PV generation is reduced due to the statistical independence of the variations in the wind and PV generation and load.
  - The aggregate wind and PV generation production level.
    - The statistics show that wind production varies more when production from 40% to 60% of maximum and PV production varies more when production is from 10% to 20% of maximum.
  - High renewable penetration will free more thermal plants to supply Regulation (after installing high speed communication).

Regulation	Load Only	2% BAU	14% RPS	20% HOBO	20% LOBO	20% LODO	20% HSBO	30% HOBO	30% LOBO	30% LODO	30% HSBO
Maximum (MW)	2,003	2,018	2,351	2,507	2,721	2,591	2,984	3,044	3,552	3,191	4,111
Minimum (MW)	745	766	919	966	1,031	1,052	976	1,188	1,103	1,299	1,069
Average (MW)	1,204	1,222	1,566	1,715	1,894	1,784	1,958	2,169	2,504	2,286	2,737
% Increase Compared to Load		1.5%	30.1%	42.4%	57.3%	48.2%	62.6%	80.2%	108.0%	89.8%	127.4%

Sample Day Showing 10-Minute Periods that Exceeded Ramp Capability

- A day with three 10-minute periods when the change in net load (red dots) exceed the ramp-up capability of the committed generators (green line).

- Table below summarizes the analytical results for several scenarios, and shows that there are relatively few periods in a year when renewable ramps exceed fleet ramping capability, and those few events would not likely cause an unacceptable decrease in PJM's Control Performance Standard (CPS) measures.



52,560 Samples	2% BAU		14% RPS		30% HOBO		30% LODO	
Number of 10-Min samples exceeding dispatched ramp capability	Count	%	Count	%	Count	%	Count	%
Ramp-up	25	0.048%	32	0.061%	322	0.613%	19	0.036%
Ramp-down	0	0.000%	0	0.000%	5	0.010%	57	0.108%

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Reserve Analysis Key Observations & Conclusions

- Significant penetration of renewable energy will increase the Regulation requirement and will increase the frequency of utilization of these resources.
    - The study identified a need for an increase in the regulation requirement even in the lower wind penetration scenario (2% BAU).
        - The average regulation requirement for the load only (i.e. no wind or PV) case was 1,204 MW.
        - This requirement increases to about 1,600 MW for the 14% RPS scenario, to a high of 1,958 MW in the 20% scenarios and then 2,737 MW in the 30% scenarios.
    - The underlying analysis used all 3-years of study load shapes and renewable profiles.
    - The study did not find any need for additional primary reserve (synchronized or non-synchronized reserve) or secondary reserve.
        - The largest wind contingency and loss of wind generation is expected to be significantly less than the largest thermal contingency in PJM or MAD sub-zone.

Challenging Days & Sub-Hourly PROBE Analysis (EnerNex/PowerGEM) [30 Minutes]

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Challenging Days Selection

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Criteria Used for Selection of Challenging Days

The following criteria were used to identify and select challenging days for detailed analysis of sub-hourly operation in the Real-Time market.

- Largest 10-minute ramp in Load Net of Renewable (LNR).
- Largest daily range in LNR (maximum LNR – minimum LNR for the day).
- Largest 10-minute ramp up or down deviations relative to the ramp capability of committed units.
- High volatility day, with largest number of 10-minute periods where the change in net load (LNR) exceeded the range capability of committed units.

Example of Challenging Days Selected

Challenging Days for 20% LOBO Scenario

- 7/15/2026,
- 2/17/2026, (Day with large period to period ramp and day with large number of periods exceeding committed resource ramp capability)
- 3/20/2026
- 7/17/2026
- 5/26/2026 (Day with large difference between LNR peak and min, and day with large number of periods exceeding committed resource range capability)
- 9/1/2026 (Day with large number of periods exceeding committed resource ramp capability and day with large number of periods exceeding committed resource range capability)

Top 10 Day's with largest difference between LNR peak and min		
Rank	Date	MW
1	7/15/2026	77,790
2	6/18/2026	76,205
3	5/26/2026	75,717
4	7/27/2026	74,991
5	7/28/2026	74,835
6	7/6/2026	73,364
7	7/23/2026	73,335
8	8/3/2026	71,786
9	7/13/2026	70,192
10	7/21/2026	69,856

Top 10 Day's with largest LNR period to period change		
Rank	Date	MW
1	2/17/2026	10,050
2	3/4/2026	9,927
3	2/12/2026	9,525
4	2/11/2026	9,457
5	2/19/2026	9,301
6	1/8/2026	9,267
7	1/20/2026	9,226
8	3/5/2026	9,173
9	1/26/2026	8,931
10	2/27/2026	8,857

Top 10- Days with largest number of ramps that exceed committed resource capability				
Rank	Date	Number	Max 10-min Ramp	MW Exceeded
1	3/20/2026	3	6,669	794
2	2/5/2026	2	8,591	2,219
3	3/2/2026	2	8,087	2,731
4	3/10/2026	2	6,932	1,447
5	9/1/2026	2	2,774	733
6	2/3/2026	1	10,050	165
7	1/26/2026	1	8,931	1,998
8	2/27/2026	1	8,857	927
9	2/17/2026	1	8,646	293
10	1/23/2026	1	8,643	368

Top 10 Days with number of periods exceeding committed resource head room				
Rank	Date	Number	Max 10-min Range	MW Exceeded
1	7/17/2026	8	10,449	7,345
2	7/28/2026	6	8,280	3,388
3	9/1/2026	6	5,244	754
4	8/3/2026	5	5,965	3,049
5	5/26/2026	4	9,387	2,133
6	9/21/2026	4	9,387	2,210
7	7/27/2026	4	7,053	3,579
8	8/4/2026	4	6,353	2,236
9	8/5/2026	4	5,675	391
10	3/19/2026	4	4,975	1,073

Sub-Hourly PROBE Analysis

PROBE Sub-hourly Simulations

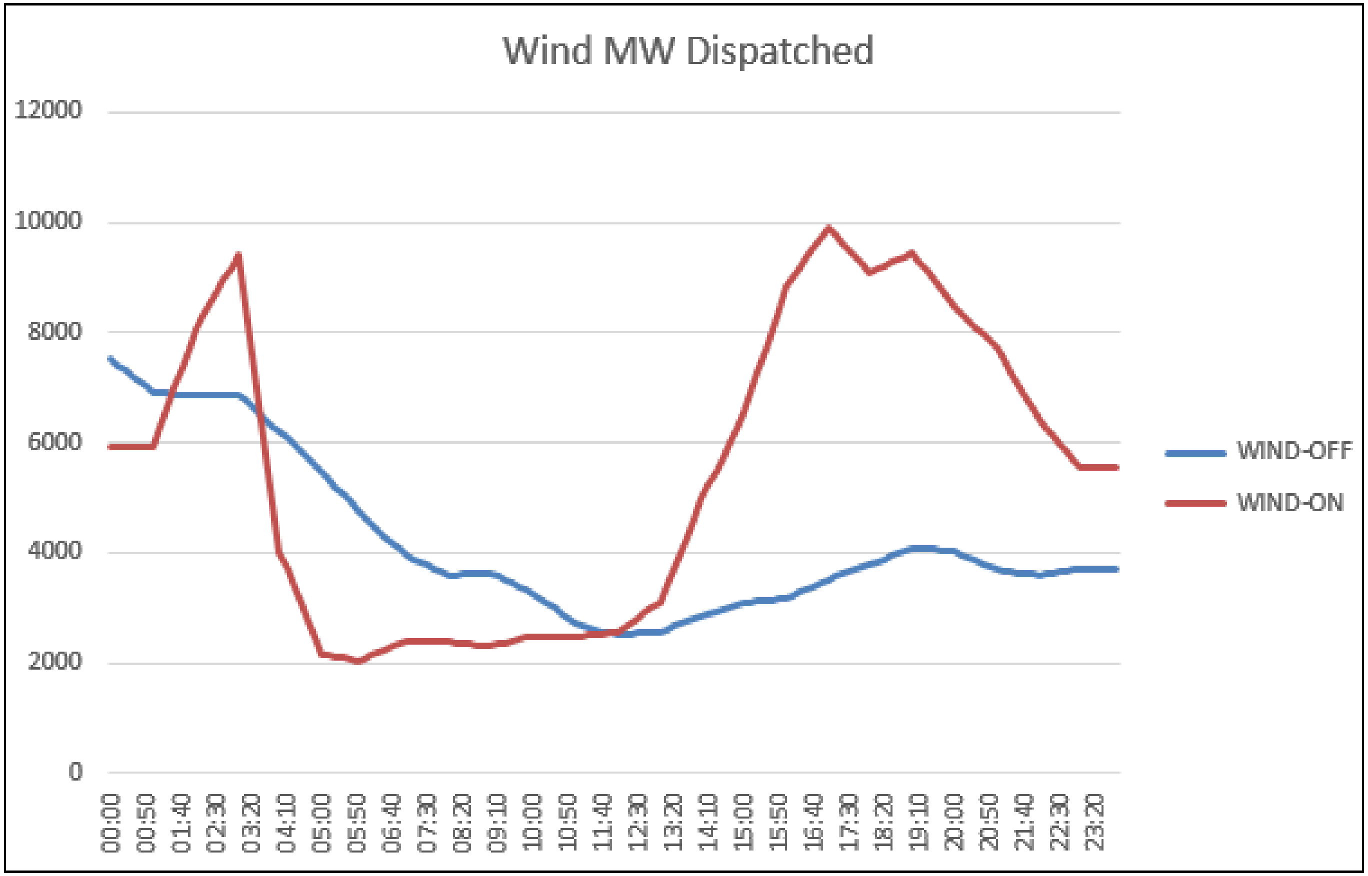
- Large changes in wind and solar generation will create more variability than the past, and the grid's flexibility to manage the variability are constrained due to the limited set of resources available and generator ramp limitations.
- The sub-hourly analysis examines issues such as:
  - Does economic dispatch of committed units keep up with sub-hourly changes in load and renewable energy output variability?
  - How does CT commitment and dispatch change in response to increased renewable resource variability?
  - Are the modeled Regulation and Reserve used to cover shortfalls? If so, how often and under what circumstances?
  - What are the impacts on short-term markets?
- A number of interesting or challenging data were selected and examined in more detail through sub-hourly modeling in PROBE.
  - Fifty simulations completed across the various 2%, 14%, 20%, and 30% profiles.

A Sub-Hourly Run Example

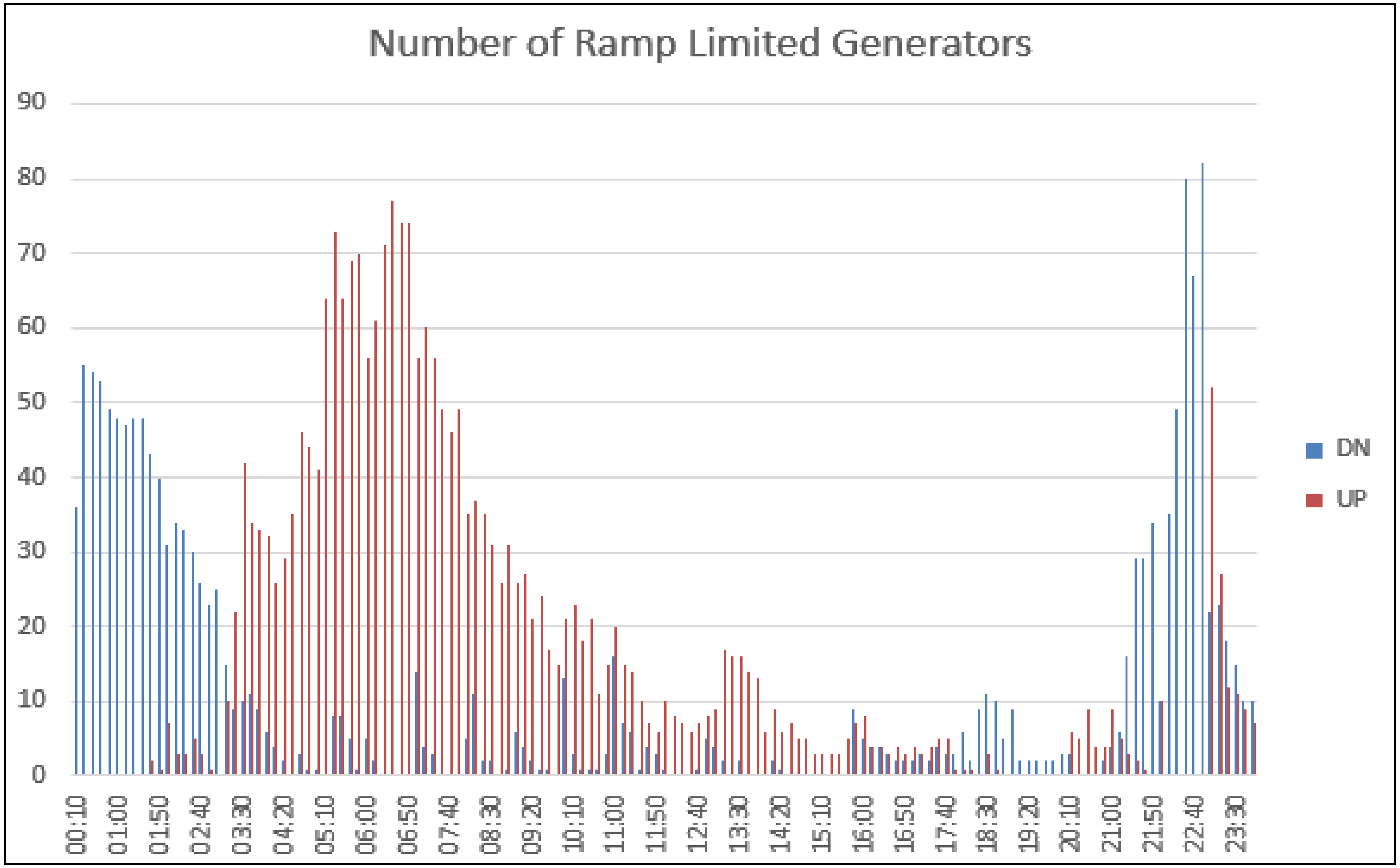
May 26 – 20% HOBO/LOBO/LODO

- Renewable profile characterized by:
  - Sharp increase in on-shore wind – followed by a sharp decrease – in the early morning
  - Another clear increase in the afternoon
- Corresponding ramp limitations
- Thermal generation is ramped down only to be quickly ramped back up an hour later
- LODO has more challenges than HOBO/LOBO
  - More transmission constraints

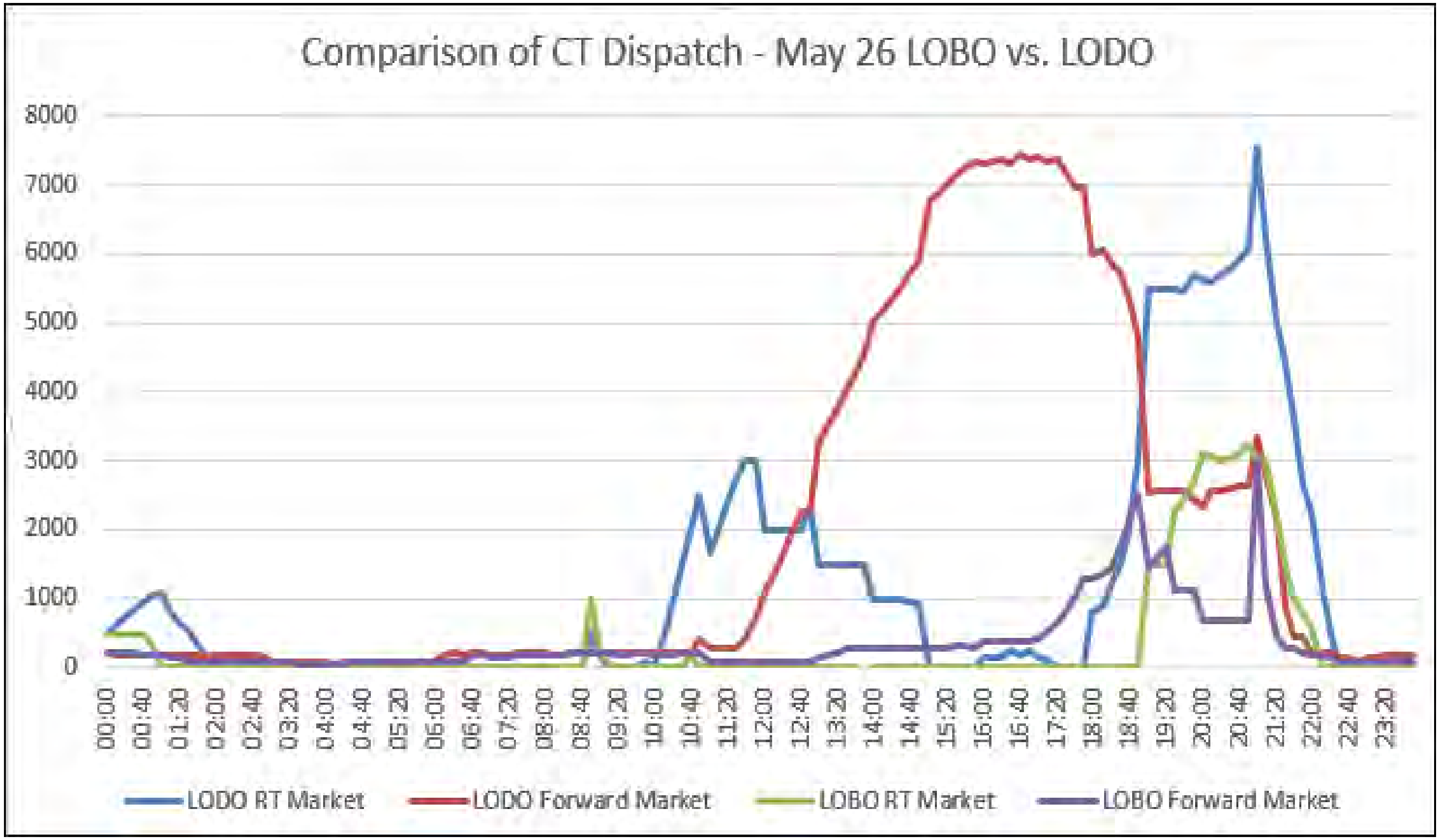
May 26 – 20% HOBO Wind



May 26 – 20% HOBO



May 26 – LOBO vs. LODO (CTs)



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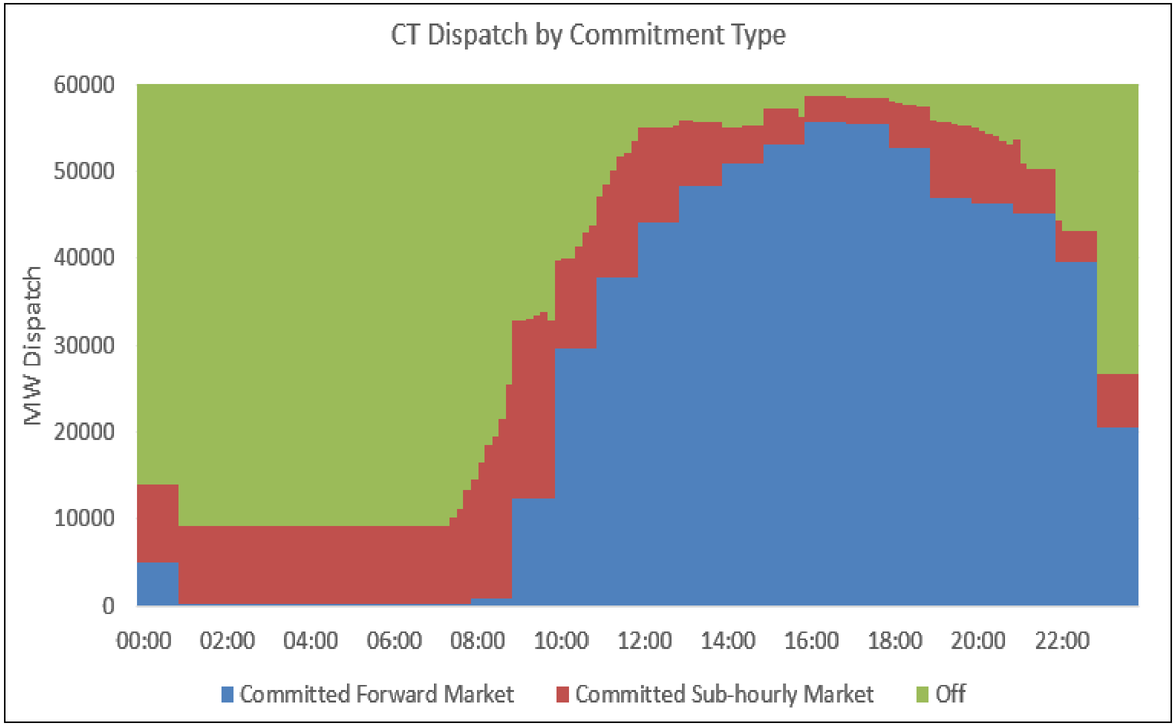
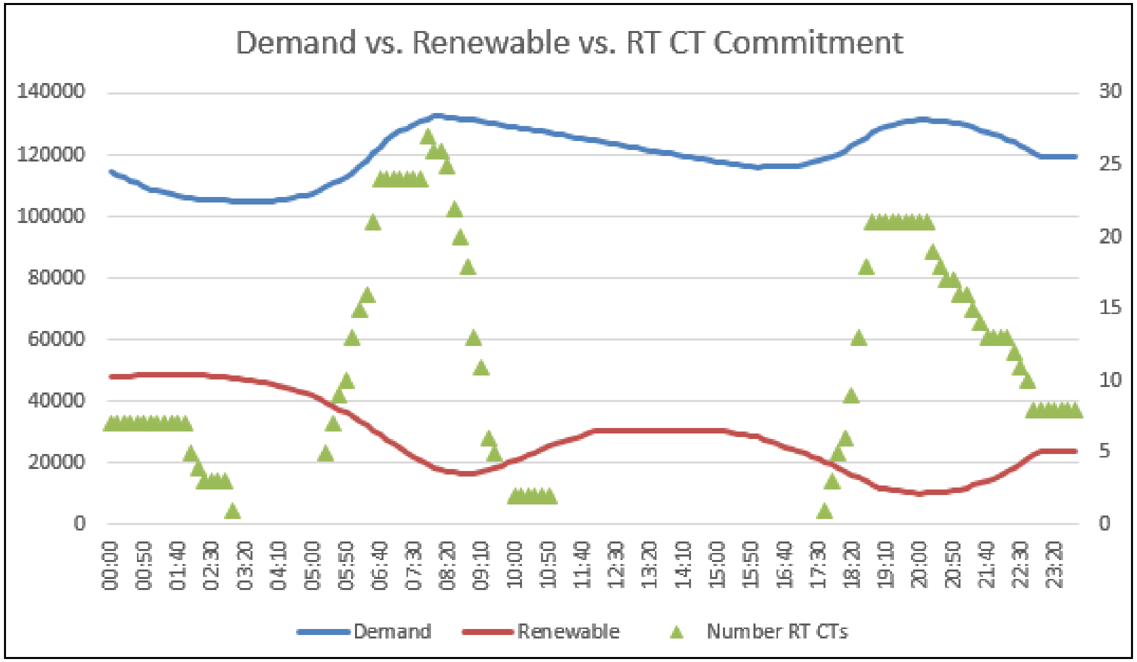
CT Capacity Committed (2% BAU, July 28)

- Figure on the right shows the CT usage for a summer-peak day in the 2% BAU scenario.
- Higher penetrations of renewable energy (20% and 30%) create operational patterns that are significantly different than what is common today, especially with respect to CT usage.



Demand MW, Renewable Dispatch, and # of CTs Committed in RT (30% LOBO, February 17)

- Figure on the right shows a plot of CT usage for February 17 in the 30% LOBO scenario.
- The blue trace is total system demand, the red trace is total renewable generation, and the green symbols show the number of committed CTs.



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General Observations and Conclusions from Sub-Hourly Analysis

- In general, all the simulations of challenging days revealed successful operation of the PJM real-time market.
  - Although there were occasionally periods of reserve shortfalls and new patterns of CT usage, there were no instances of unserved load.
  - The level of difficulty for real-time operations largely depends on the day-ahead unit commitment.
- Higher penetrations of renewable energy (20% and 30%) create operational patterns that are significantly different than what is common today.
  - The previous plots illustrate trends observed in many of the high renewable scenarios, where CT's are used less during peak load periods and more during periods where there are rapid changes in load, wind, and solar (particularly during the beginning and end of the solar day, when solar power output ramps up or down) or to compensate for errors in the day-ahead renewable energy forecast.

Power Plant Cycling Costs & Emissions Analysis
(Intertek AIM)
[30 Minutes]

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Power Plant Cycling Costs Analysis

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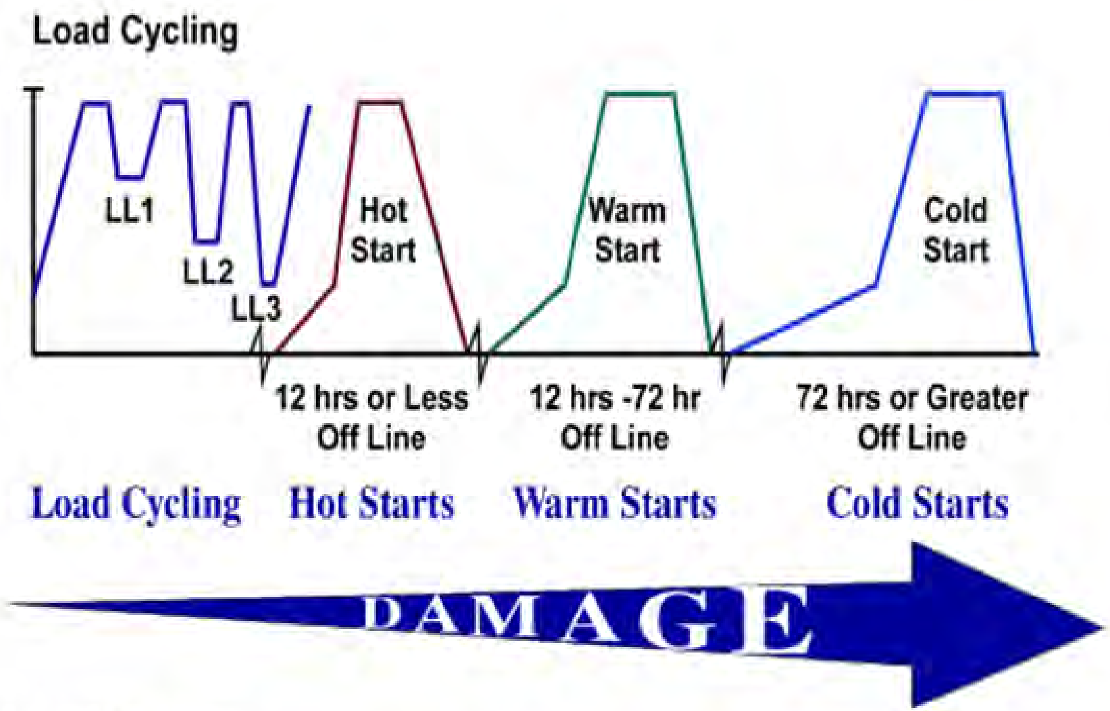
Cycling Cost Analysis Objective and Approach

Further integration of renewable resources into the grid are expected to drive higher cycling by thermal power plants. The objective of this task was to provide estimates of cycling related wear-and-tear costs and variable O&M costs.

- The Intertek AIM's unit commitment model – Cycling ⬍ Advisor ™ (CA) and Loads Model™ (LM) was utilized to evaluate the damage and damage cost to assess impacts of unit cycling.
- The models were used to derive the incremental variable O&M costs of power plant operation by utilizing the models' ability to model unit cycling damage.
- Intertek's work for NREL on the WWSIS Phase II Study was leveraged to determine the incremental cost of cycling. The estimates in the WWSIS Study were based on historical cycling. This study extends the cost estimates to include the cycling from increased renewable penetration.

Types of Cycling Duty That Affect Cycling Costs

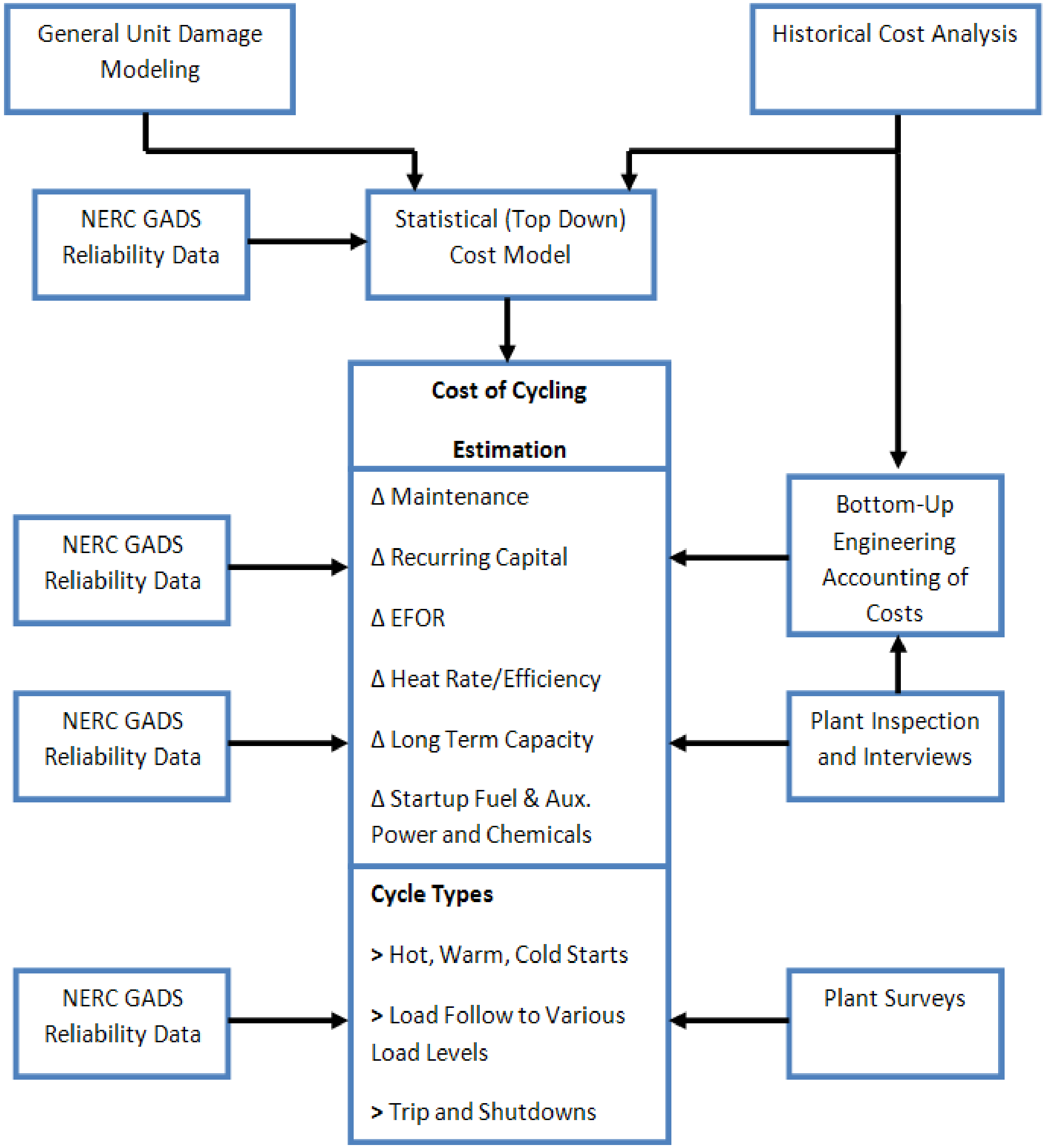


Load Cycling

- LL1: Lowest Load at which design SH/RH temperatures can be maintained
- LL2: Current "Advertised" Low Load
- LL3: Lowest Load at which the unit can remain On-Line

*Offline Hours are only for representation. Different generation types and units will have different offline hours to represent cycle types

Cost of Cycling Estimation Procedure



Project Methodology – Baseline Criteria

- Baseline = Historical Operation from 2000-2012 [Hourly MW data of actual plant operations]
- Added 1 additional year of Hourly MW generation (from GE MAPS) for every unit (150 total units) to historical operation.

Up to 12 Year Actual Operating Profile

[CY 2000-2012]

Analysis Methodology

- Use Loads Model ™ Cycling Damage Algorithm to determine cycling profile (**for each unit type**) and generate damage parameter
- Cost Regression Model to fit baseline operation to baseline 2012 costs

Baseline Damage (EHS) for operating profile

Hourly MW 2000-12

Assume instantaneous addition of renewable

- *Ignores operating profile between now and future.*
- *Power plants will accumulate cycles and therefore damage (cost) from now until future scenario date*
- *Recommend running intermediary scenarios to capture this.*

Actual Operating Profile

+ 1 Additional Scenario Year

[CY 2000-2012 + Scenario Year]

Analysis Methodology

- Use Loads Model ™ Cycling Damage Algorithm to determine cycling profile and generate damage parameter with additional scenario operating profile
- Cost Regression Model to fit baseline cost to scenario operating profile

Scenario Damage (EHS) for operating profile

Scenario MW Profile

Hourly MW 2000-12 + Scenario

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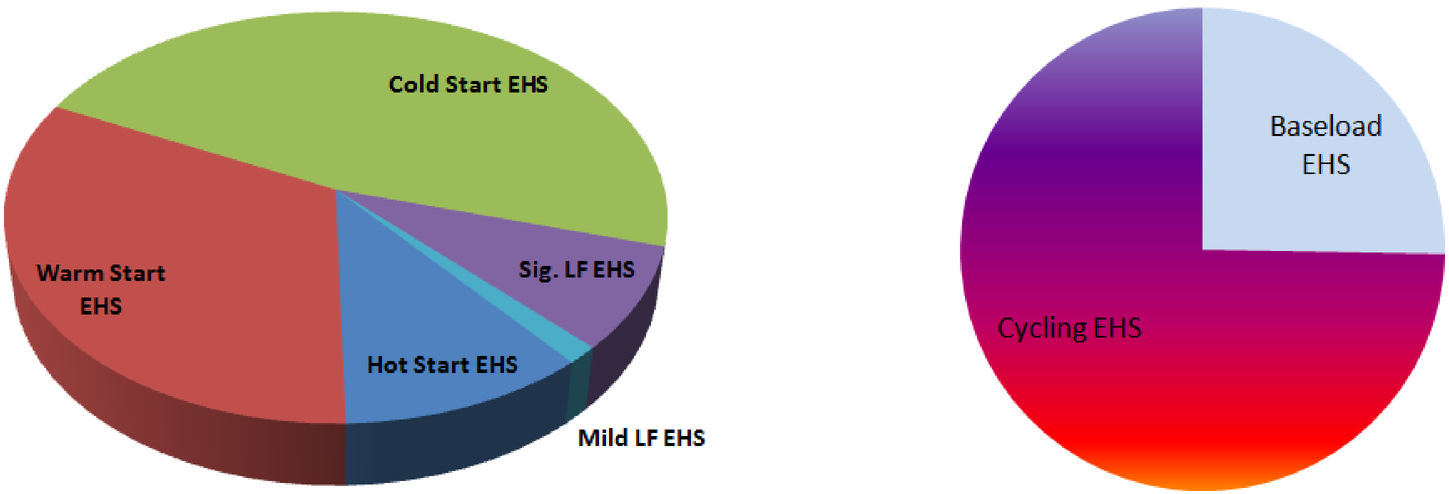
Characterizing Damage and Costs

- Plant cycling characteristics can be classified in terms of Baseload and Cyclic Equivalent Hot Starts (EHS).
- Within the cyclic EHS, there are different operating patterns that contribute towards cost and damage (chart on left).
- Publicly available data on Variable O&M does not include majority of cyclic costs.

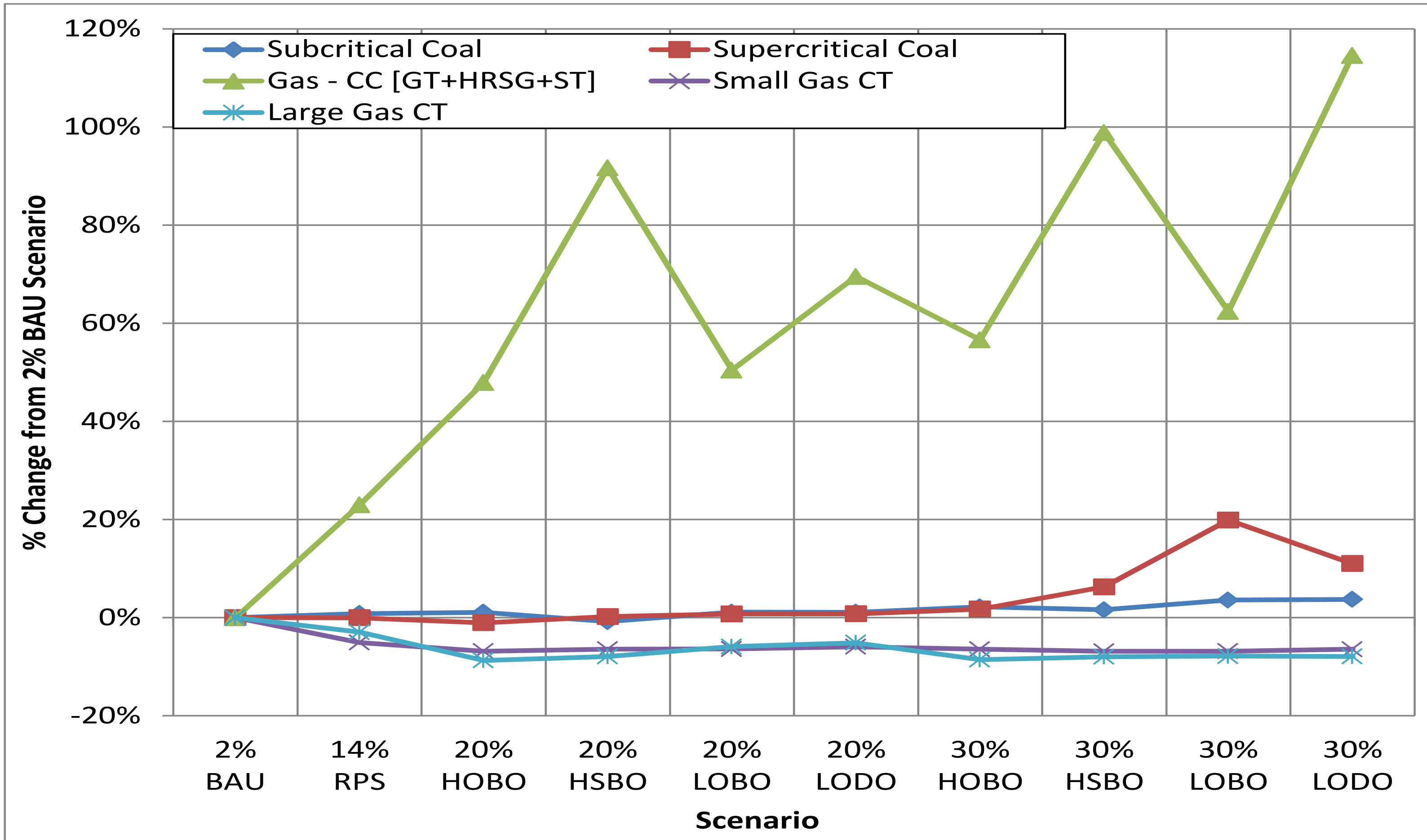
Characterizing Damage Parameter (EHS) for different operating profiles.



EHS = Damage per Cycle {Hot, Warm, Cold, Sig. Load Follow, Mild Load Follow}
OR
EHS = Baseload EHS + Cycling EHS

Changes in Cycling Duty Compared to 2% BAU Scenario

- Biggest change in operations on CCGT units followed by Supercritical Coal



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Examples of Cycling Costs in $/MWh

	2% BAU	14% RPS	20% HOBO	20% HSBO	20% LOBO	20% LODO	30% LOBO	30% HSBO	30% HOBO	30% LODO
Subcritical Coal	$1.14	$0.61	$1.78	$0.51	$0.69	$0.59	$1.09	$1.46	$2.52	$1.01
Supercritical Coal	$0.09	$0.11	$0.21	$0.15	$0.15	$0.14	$0.99	$0.31	$0.34	$0.46
Combined Cycle [GT+HRSG+ST]	$1.80	$2.69	$6.29	$5.19	$4.77	$4.68	$5.43	$7.55	$6.76	$5.81
Small Gas CT	$1.65	$1.74	$0.41	$0.52	$0.51	$0.60	$0.92	$0.87	$0.51	$0.82
Large Gas CT	$3.32	$3.41	$1.88	$2.68	$2.19	$2.42	$1.56	$1.52	$1.85	$2.02

Note: Cycling Costs = [Start/Stop + Significant Load Follow]
Note: Costs are related to lower MWh generation on different unit types.

Cycling Cost Analysis Conclusions

- Increased renewable integration results in increased cycling on existing fossil generation.
  - CCGT Units perform majority of the On/Off cycling in the scenarios, with the coal units performing the load follow cycling.
  - On an absolute scale, the cost of On/Off and Significant Load Follow increases the most on Supercritical and Combined Cycle Units.
- Increased cycling damage does not have a linear relation with cost alone.
  - Increased cycling results in increase in forced outage rates (reliability impacts), which should be included.
- In almost each of the scenarios, the coal and combined cycle units perform increasing amounts of cycling; resulting in higher cycling related VOM cost and reduced Baseload VOM Cost, where:
  - Total Variable O&M (VOM) Cost = Baseload VOM + Cycling VOM.

Power Plant Emissions Analysis

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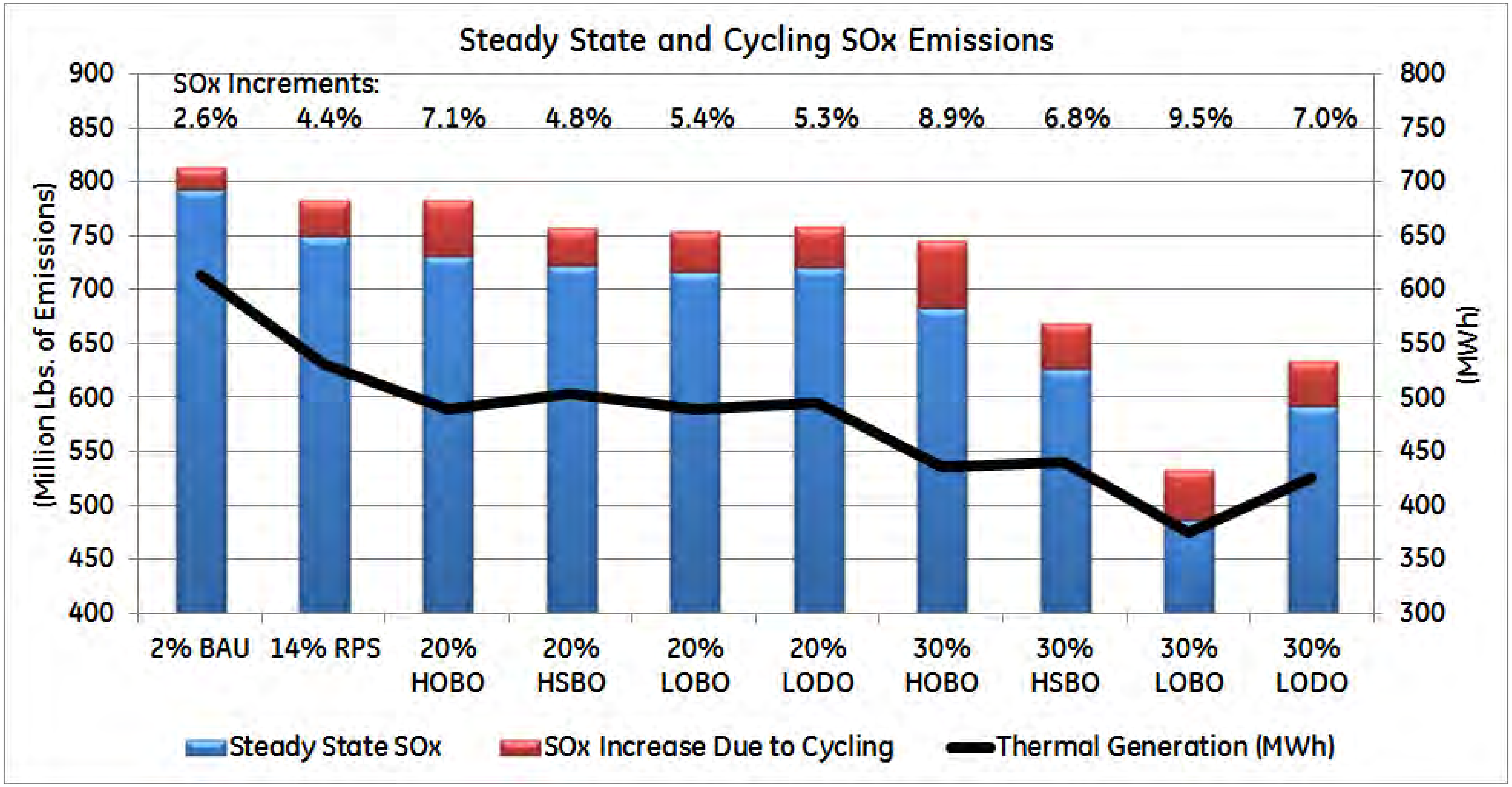
Emissions Analysis Objective and Approach

- Variability of renewable energy resources requires the coal and gas fired generation resources to adapt with less efficient ramping and cycling operations, which in turn impacts their environmental emissions.
- This study examines the changes in emissions amounts and rates for the PJM portfolio for each of the study scenarios which differ in the level of cycling operations of the units.
  - Actual historical power plant emissions were analyzed to derive the impact of plant cycling on each type of power plant.
  - The output from GE MAPS presents the steady state "without cycling" emission amounts, which are then updated using Intertek's regression outputs to generate the "with cycling" emissions estimates.
- The system-wide emissions of high renewable penetration scenarios were compared to the 2% BAU scenario.
  - Total Emissions = Steady State (from GE MAPS) + Extra Cycling-Related Emissions (from Interek AIM Regression Model)

Regression Variables and Type of Plants Studied

- A period of hourly emissions for 3 years was evaluated (initially 12 years, but emissions control was installed on most units mid decade).
  - The regression of the historical measured emissions data for each of the six unit types uses several independent variables:
    - load,
    - time period,
    - months of year,
    - individual unit,
    - start/shutdown cycles,
    - weekend-holiday vs. work day,
    - emission control, and
    - load follows greater than 20% of the unit's full capacity.
  - The system-wide incremental changes in air emission were estimated for the following six conventional plant generation types:
    - Sub-Critical Coal (35-900 MW)
    - Large Supercritical Coal (500-1300 MW)
    - Combined Cycle Units based on LF CT Cost
    - Small Gas CT (< 50 MW)
    - Large Gas CT (50-200 MW)
    - Gas Fired Steam Plants (50 MW-700 MW)

SOx Emissions for Study Scenarios, With and Without Cycling Effects Included



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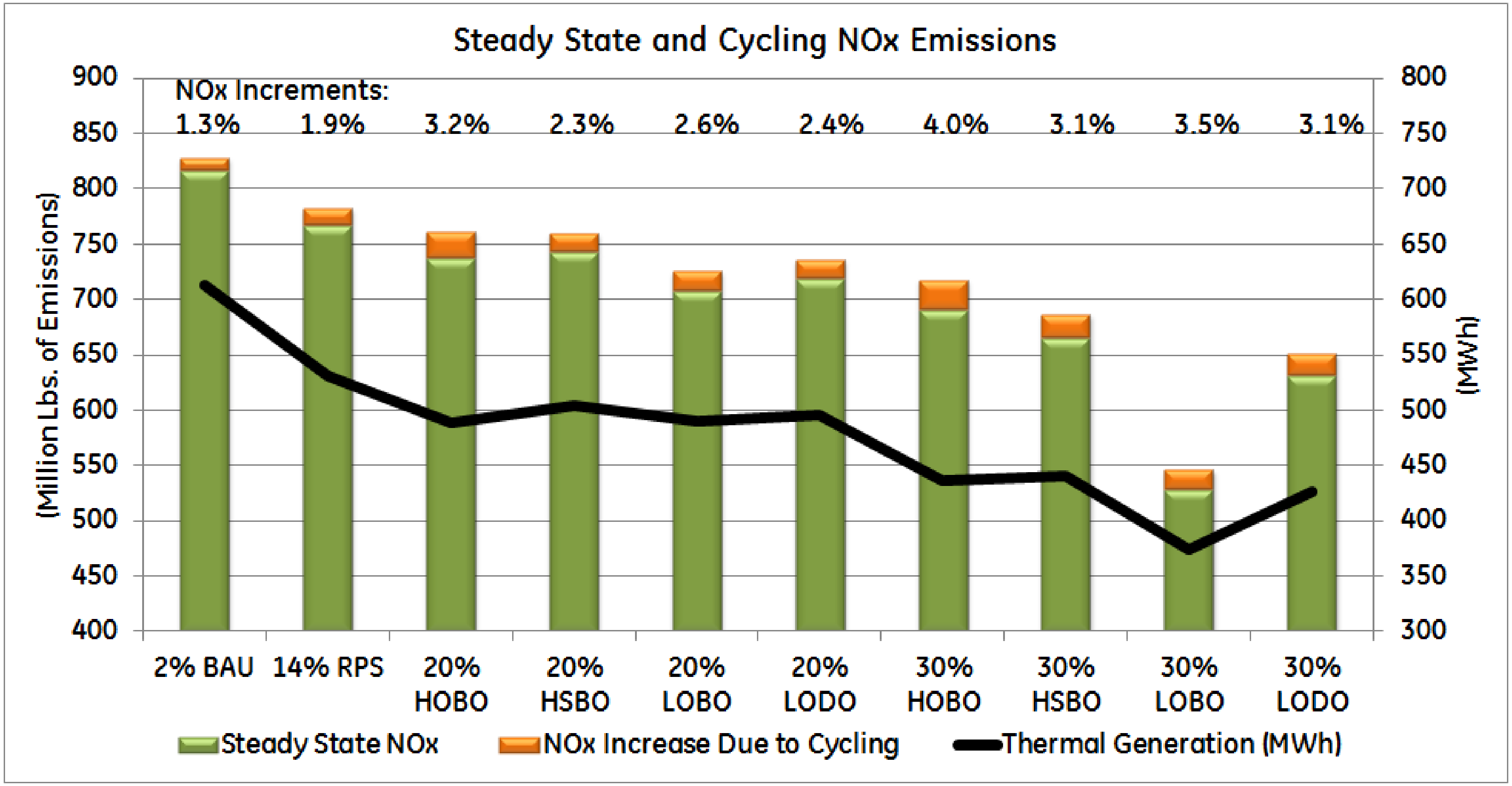
NOx Emissions for Study Scenarios, With and Without Cycling Effects Included



Cycling Impacts for NOx and SOx Emissions Relative to the 2% BAU Scenario

Compared to 2% BAU Scenario	SOX Expected Steady State Reduction in Emissions	SOX Expected Emissions Reduction with Cycling Impacts
14% RPS	5%	4%
20% HOBO	8%	4%
20% HSBO	9%	7%
20% LOBO	10%	7%
20% LODO	9%	7%
30% HOBO	14%	9%
30% HSBO	21%	18%
30% LOBO	39%	35%
30% LODO	25%	23%

Compared to 2% BAU Scenario	NOX Expected Steady State Reduction in Emissions	NOX Expected Emissions Reduction with Cycling Impacts
14% RPS	6%	6%
20% HOBO	10%	8%
20% HSBO	9%	9%
20% LOBO	14%	13%
20% LODO	12%	12%
30% HOBO	16%	14%
30% HSBO	19%	18%
30% LOBO	36%	36%
30% LODO	23%	22%

Total MWh, Heat Input, and CO2 Emissions Relative to the 2% BAU Scenario

Compared to 2% BAU Scenario	Reduction in MWh Energy Output from Coal and Gas plants	Reduction in Heat Input (Fuel)	Reduction in CO2 Emissions
14% RPS	15%	14%	12%
20% HOBO	20%	18%	14%
20% HSBO	18%	16%	15%
20% LOBO	19%	19%	18%
20% LODO	18%	18%	17%
30% HOBO	35%	32%	27%
30% HSBO	31%	29%	28%
30% LOBO	40%	40%	41%
30% LODO	30%	29%	29%

Relative Contribution of On/Off Cycling and Load-Follow Cycling to Total Emissions

	SOX Impact From		NOX Impact From	
	On/Off	Load Follow	On/Off	Load Follow
2% BAU	0.3%	2%	0%	1%
14% RPS	0.4%	3%	1%	2%
20% HOBO	0.3%	6%	0%	3%
20% HSBO	0.4%	4%	0%	2%
20% LOBO	0.6%	4%	1%	2%
20% LODO	0.6%	4%	1%	2%
30% HOBO	0.5%	7%	1%	4%
30% HSBO	0.7%	5%	1%	2%
30% LOBO	1.2%	6%	1%	2%
30% LODO	1.0%	5%	1%	2%

- This is the contribution of cycling transients to the total emissions (steady + cyclic).
- Load follow results are dominated by Supercritical Coal

Cycling Emissions Analysis Conclusions

- The main observations and conclusions from this analysis are:
  - Emissions from coal plants comprise 97% of the NOx and 99% of the SOx emissions.
  - For scenarios that experience increased cycling, the results are dominated by supercritical coal emissions.
  - NOx and SOx rates (lbs./MMBtu) increase at low loads for coal plants and decrease for CTs.
  - Load follow cycling is the primary contributor of cycling related emissions.
  - Including the effects of cycling in emissions calculations does not dramatically change the level of emissions for scenarios with higher levels of renewable generation. However, on/off cycling and load-following ramps do increase emissions over steady state levels. This analysis has provided quantified data on the magnitudes of those impacts.

Task 3b: Market Analysis (EnerNex/PowerGEM/Exeter/GE) [30 Minutes]

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Market Analysis Tasks

- Study Methods For Determining Operational Reserve Requirements
  - Recommended an Approach for Implementation in PJM Operations
- Dealing With Uncertainties In The Real Time Market
- Energy And Ancillary Services Co-optimization In DA Market
  - Consideration of Impact of Short-term Forecast and Security Constrained Unit Commitment
  - Performed 5 Sub-Hourly PROBE Simulations
    - 14% RPS, May 26: 4-hour ahead wind and solar forecast
    - 14% RPS, February 17: High carbon price, low gas price
    - 14% RPS, May 26: Perfect wind and solar day-ahead forecast
    - 20% LOBO, February 17: Reduced wind/solar forecast error
    - 30% LOBO, February 17: High carbon price, low gas price
- Best Practices From Other Markets
  - Investigated experience from other markets
  - Report already issued by Exeter Associates

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Study Methods For Determining Regulation Requirements

Regulation - Theory & Practice

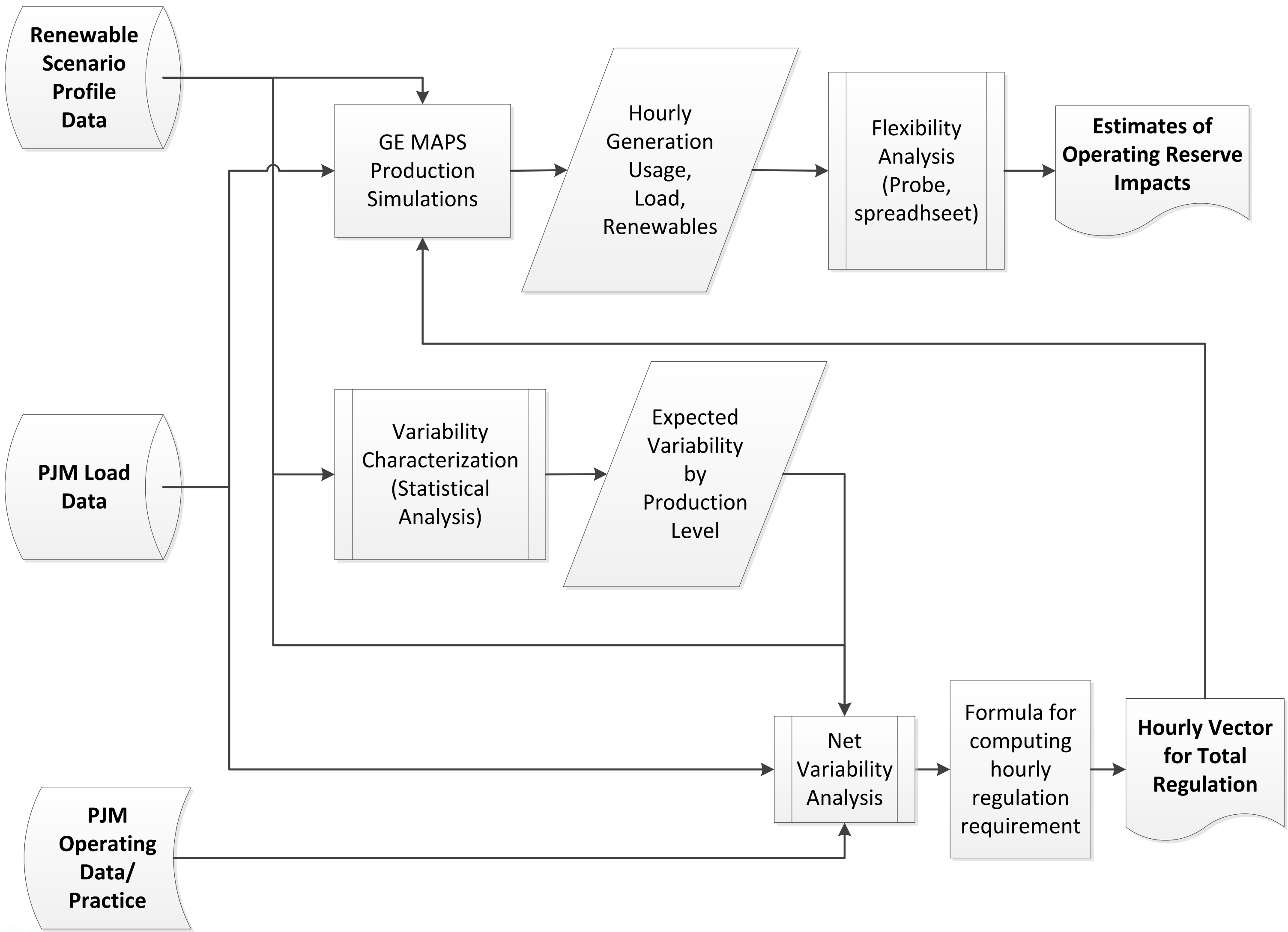
- In Task 3a the sub-hourly variability of wind + solar resources was analyzed statistically in a previous task of this project.
  - Through that analysis, it was possible to calculate the amount of additional regulation that would be needed within the PJM operating area as a function of the aggregate wind and solar power output.
- In Task 3b, an approach is presented for incorporating that methodology into day-ahead and real time operations of the PJM system.
  - The approach entails a day-ahead reserve commitment accounting for day-ahead wind + solar variability, augmented by short-term wind + solar forecasts, resulting in a real-time regulation commitment.
  - Due to the size and geographic spread of the PJM system, no additional 10-minute spinning reserves are required to cover forecast uncertainty.

Current PJM Practice for Assessing Requirements for Frequency Regulation

- Fast responding resources can lower overall frequency regulation requirements.
  - On October 1, 2012, PJM implemented new methodology to compensate better performing resources (like storage), in compliance with FERC Order No. 755.
  - In conjunction with this change, PJM reduced its off-peak and on-peak regulation requirement from 1.0% of the day ahead valley load forecast and peak load forecast respectively to 0.7%.
  - On August 1, 2013 PJM members approved a change to PJM Manual M12 which was implemented on 12/1/2013. The regulation requirement is uniform for all on-peak hours (0500 - 2359) at 700 effective MW and all off-peak hours (0000 - 0459) at 525 effective MW.
  - DR and storage (batteries, fly wheels, electric vehicles, electric water heaters) can be a cost-effective source of system flexibility.

Note: Based on the information available at the start of this project, this study assumed off-peak and on-peak regulation requirements of 1.0% of the day ahead valley load forecast and peak load forecast, respectively, which is different from the current practice.

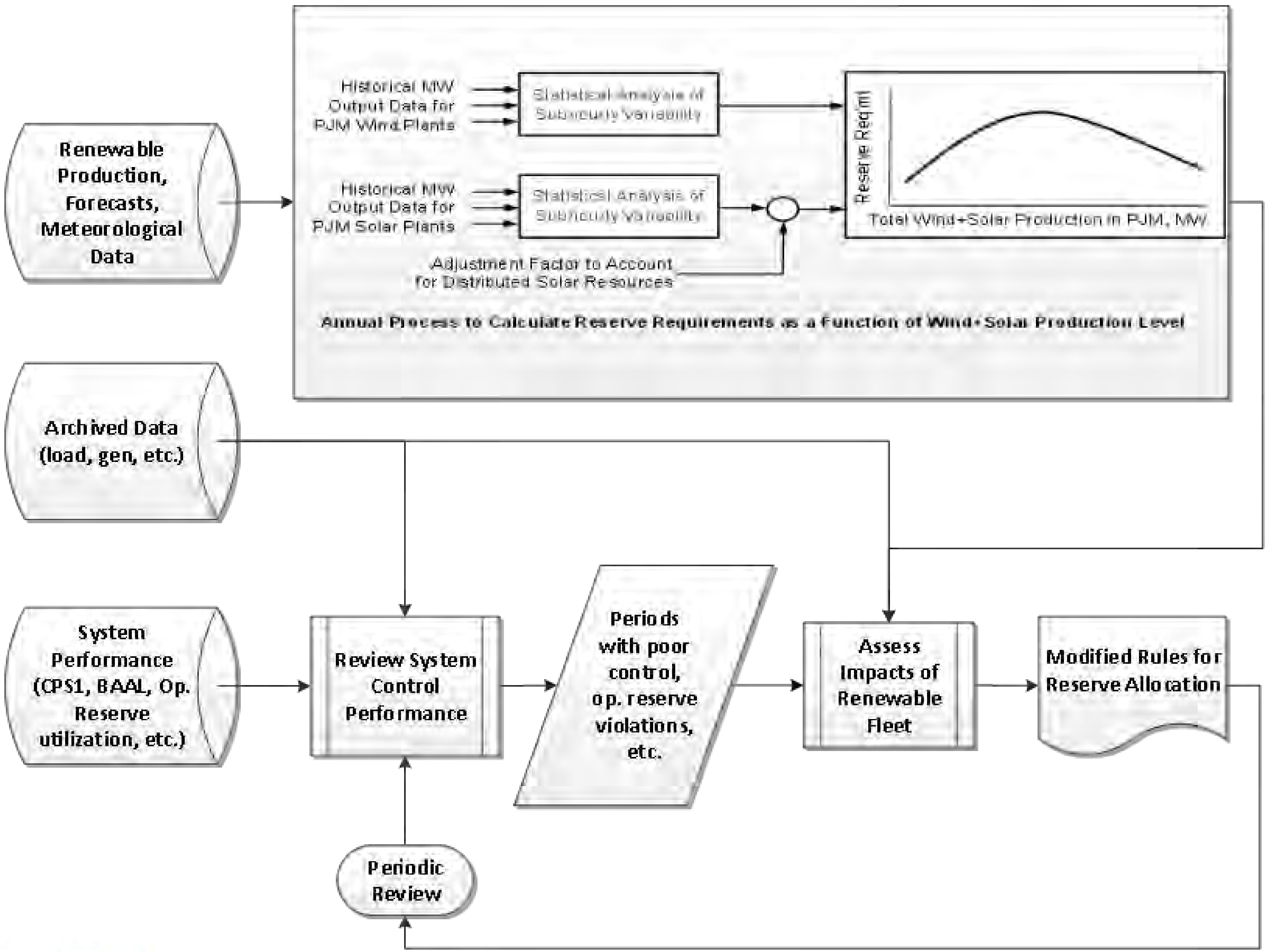
Procedure for Analyzing Renewable Impacts on Regulation & Operating Reserve



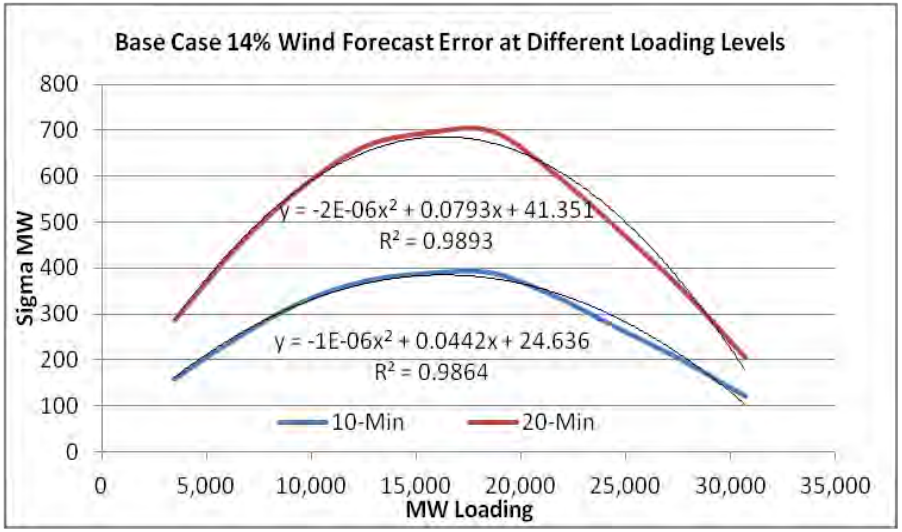
Possible Approach for Implementation in PJM Operations

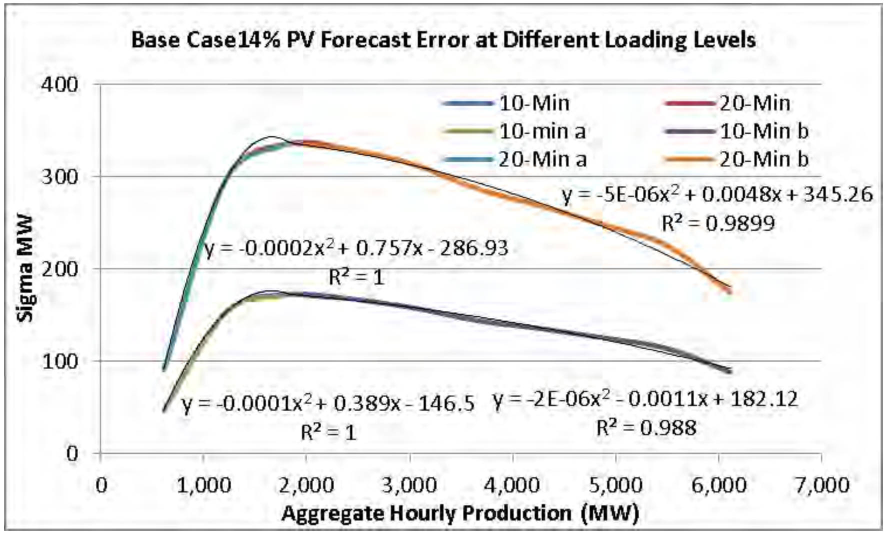
- Using the described process, this study developed curves of regulation requirements for the PJM operating area as a function of aggregated wind and solar power production, above and beyond the customary contingency based reserve.
- The approach used in the study could be adapted to provide a framework for evolving PJM's operational practice as the penetration of renewable generation grows.
- The aforementioned reserve vector derived from the statistical analysis approximates a process where reserve requirements are determined on the basis of load forecasts and short-term forecasts of renewable generation.

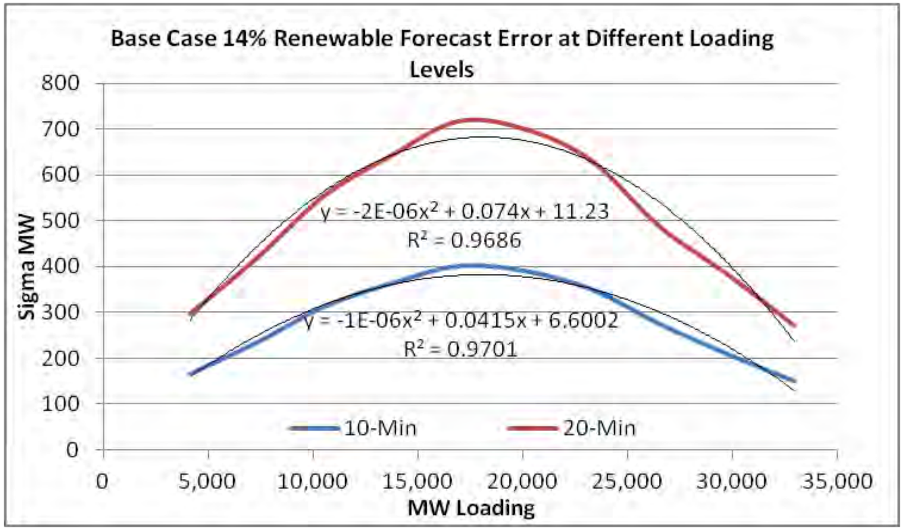
Adaptation into Operations Planning



Statistical Characterization of Wind, Solar PV, and Aggregate Production







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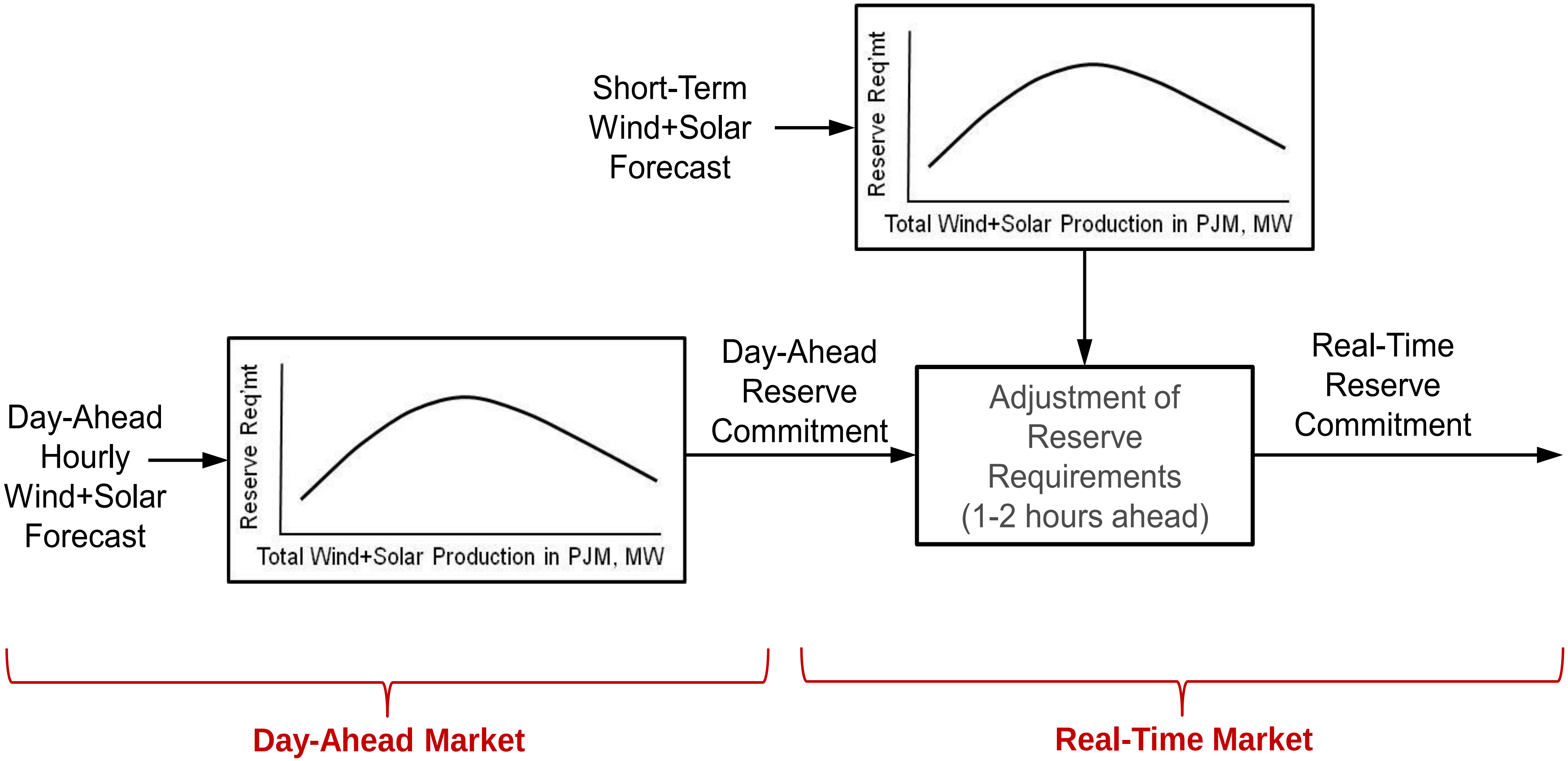
Dynamic Regulation Requirement

- The procurement of regulation becomes more challenging as the regulation requirement becomes much more dynamic.
- Since the procurement must happen in advance of the need, decisions will necessarily be based on forecasts.
- The nature of renewable generation forecasting would dictate that these decisions be made as close as possible to the time of actual need.
- However, the time constants associated with market mechanisms do require some lead time.

Recommended Approach

- PJM currently bases regulation requirements on next-day forecasts of peak and valley loads, so the structure already in place has the basic attributes.
- The study recommends a methodology whereby the day-ahead reserve commitment accounts for the day-ahead wind and solar forecast, which then gets adjusted by short-term wind and solar forecast, resulting in a real-time reserve commitment.
- Due to the size and geographic spread of the PJM system, no additional 10-minute reserve are required to cover forecast uncertainty.

Suggested Daily Process for Calculating Regulating Reserves Required for Real-Time Operations



Break

Dealing With Uncertainties In The Real Time Market

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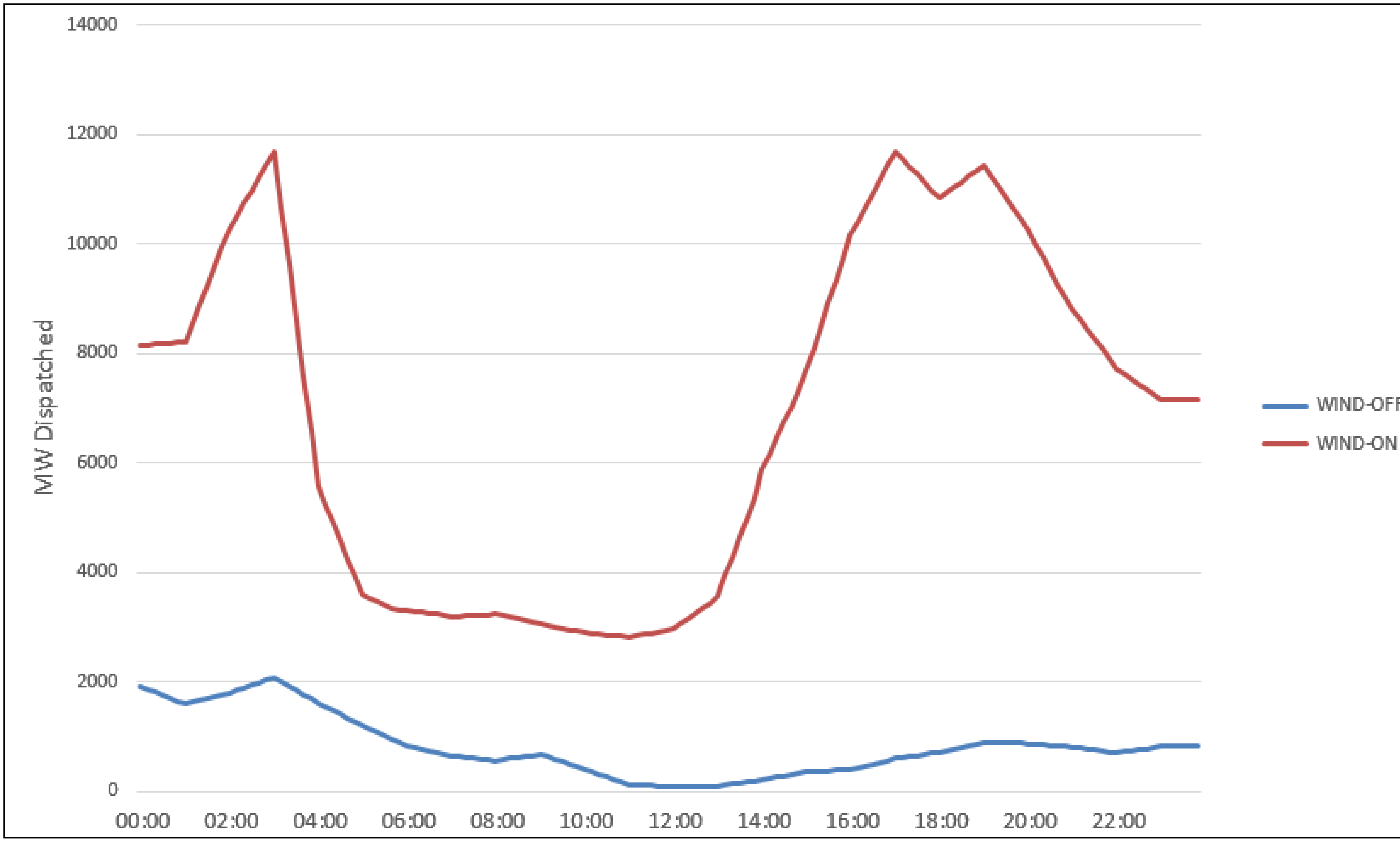
Market Analysis Tasks

- Objective: To investigate:
  - Dealing With Uncertainties In The Real Time Market
  - Energy And Ancillary Services Co-optimization In DA Market
- The following sub-hourly sensitivities were agreed to be performed on previously selected challenging days and scenario combinations in order to study the uncertainties in the real time market and the impact of short-term forecast and security constrained unit commitment.
  - 14% RPS, May 26: 4-Hour Ahead Wind and Solar Forecast
  - 14% RPS, May 26: Perfect Wind and Solar Day-Ahead Forecast
  - 20% LOBO, February 17: Reduced Wind/Solar Forecast Error
  - 14% RPS, February 17: Low Gas Price, High Carbon Price
  - 30% LOBO, February 17: Low Gas Price, High Carbon Price

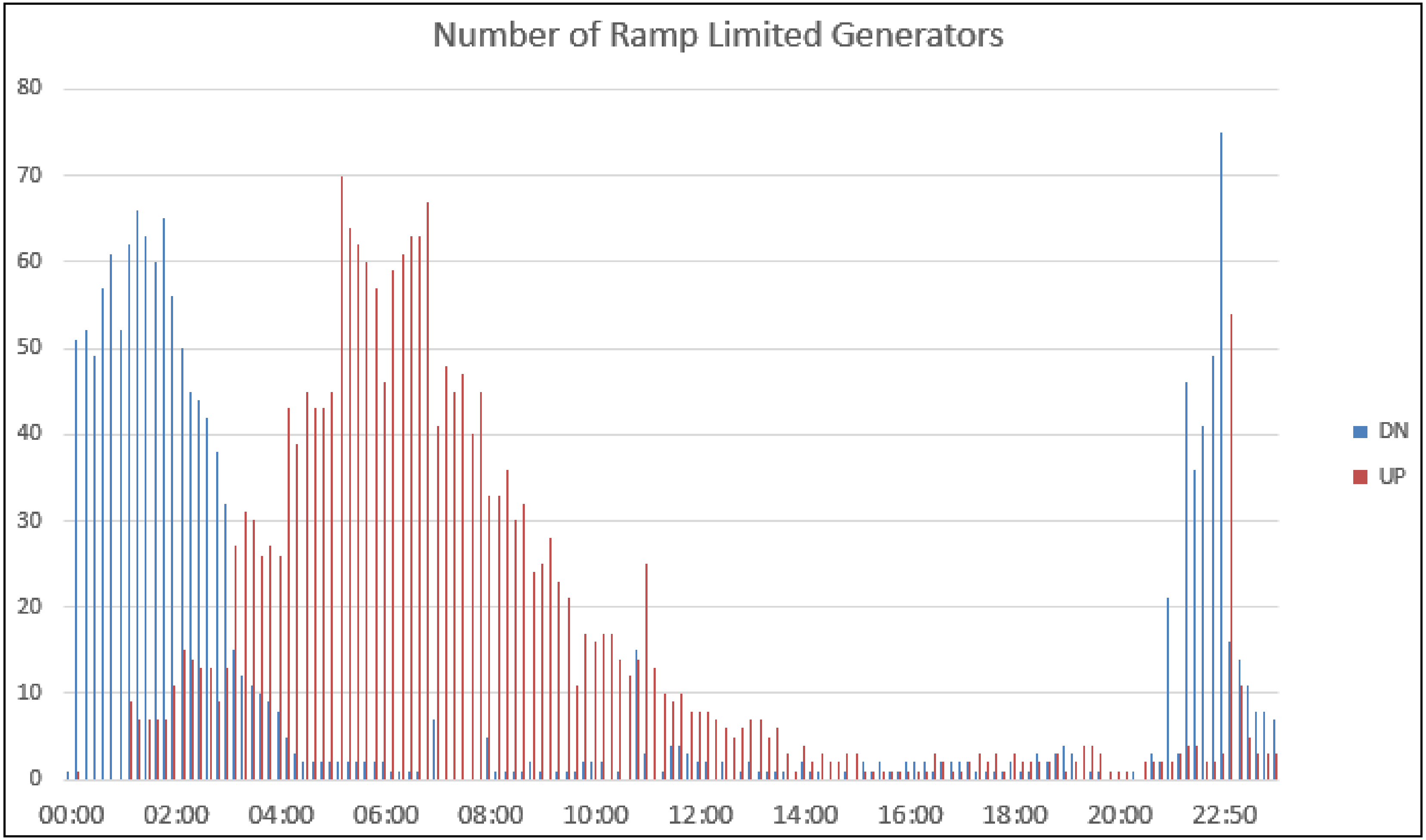
4-Hour Ahead Wind and Solar Forecast 14% RPS - May 26

- This sensitivity considers impact of less uncertainty with a 4-hour forecast of wind and solar and unit commitment.
- May 26 is largely defined by a sharp increase in on-shore wind just after midnight, followed by a sharp decrease in the early morning, with another clear increase in the afternoon, as shown in the following figure.
- Observations / Characteristics:
  - Low headroom during several intervals.
  - Large number of ramp constraints; quick change between generators ramping down and then ramping back up.
  - Significantly less CT commitment in real-time than the baseline 14% RPS simulation for this day, as measured both by number of CTs and MW dispatched from CTs.

Wind Generation Output (14% RPS - May 26)



Number of Ramp-Constrained Units per 10-Minute Interval (14% RPS - May 26)



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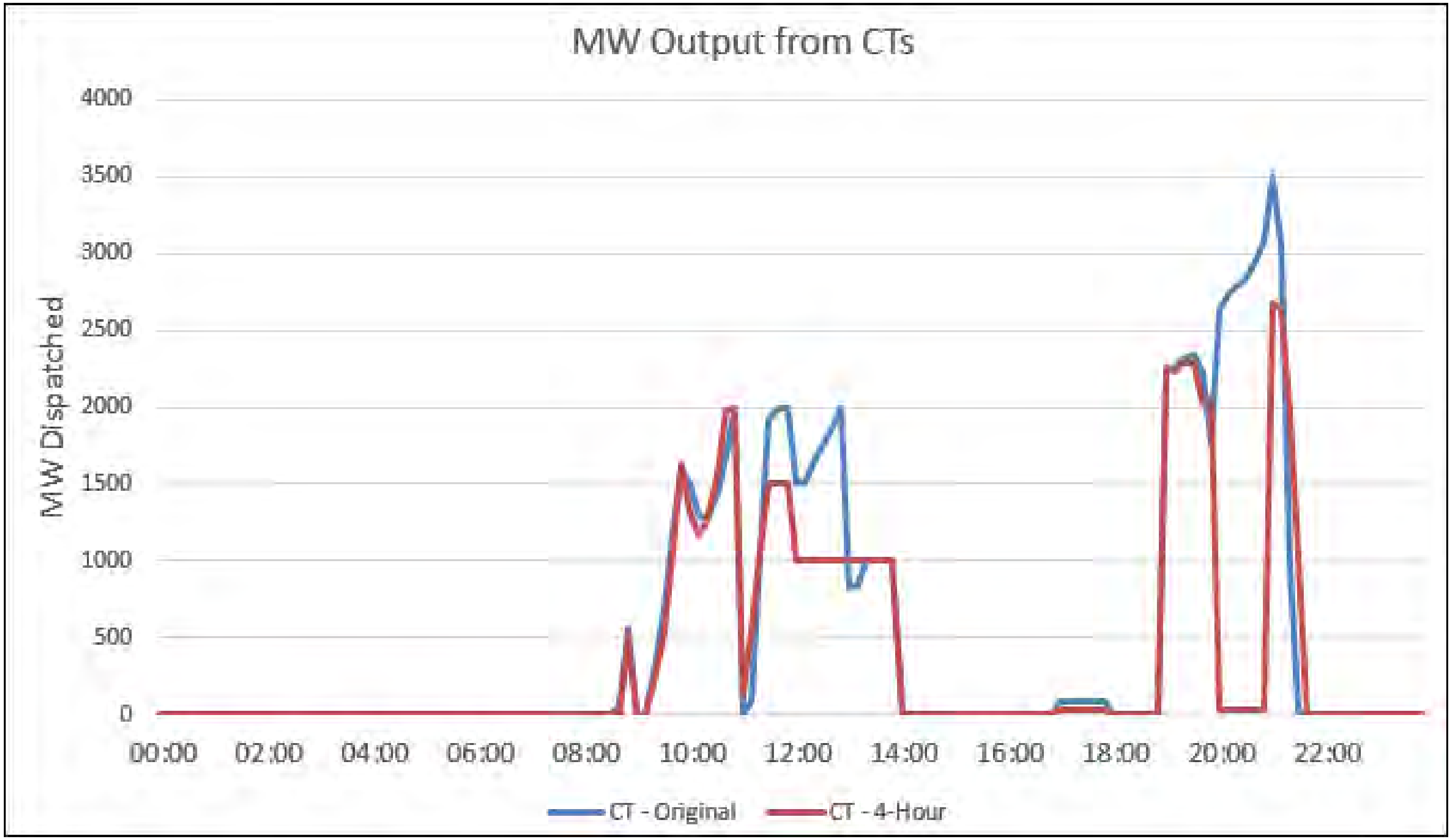
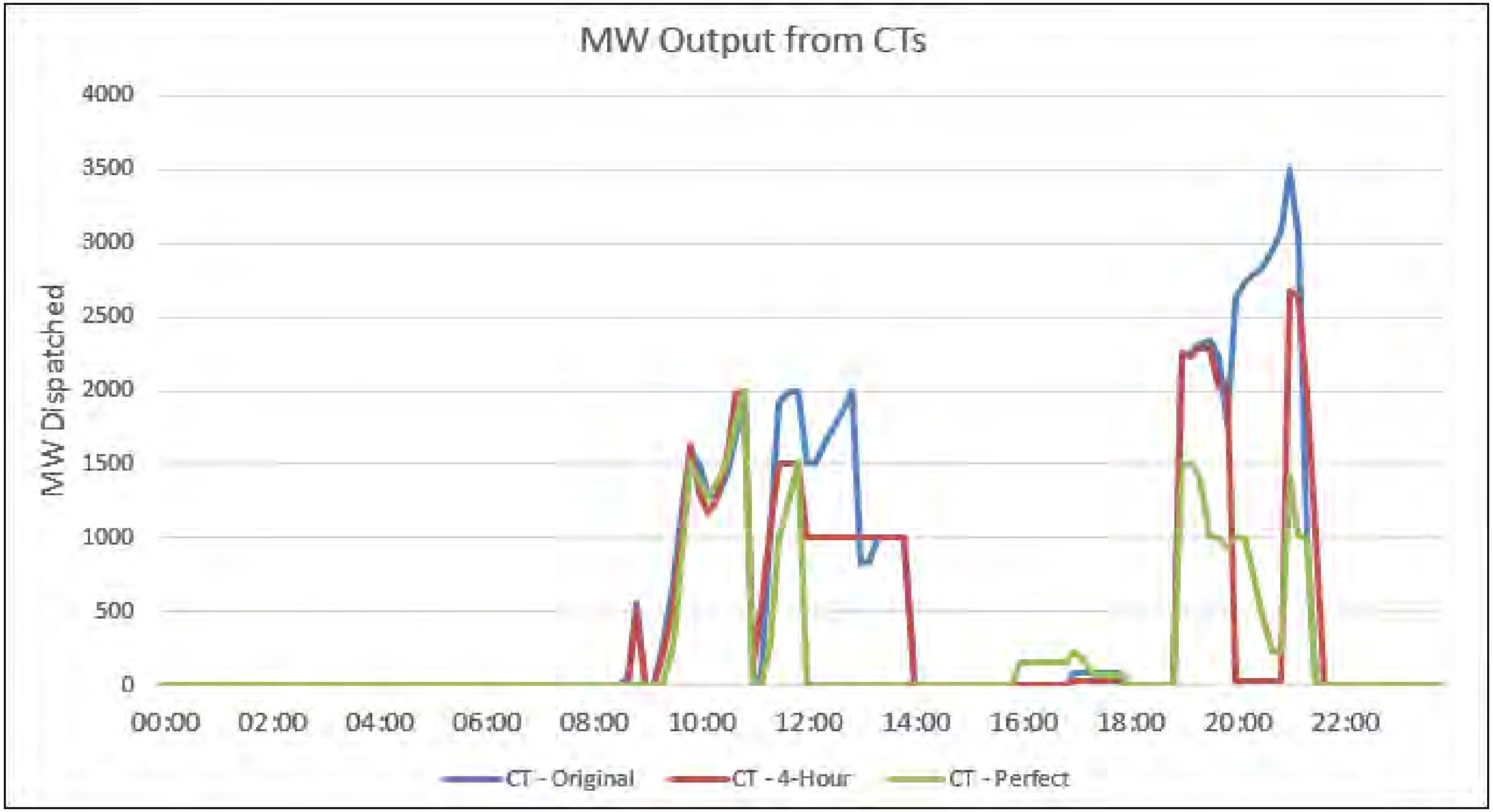
CT Dispatch by Interval (14% RPS - May 26)



Perfect forecast (14% RPS – May 26)

- This sensitivity considers impact of no uncertainty with perfect forecast of wind and solar.
- Using the "perfect forecast" provided additional benefits as compared to the other 14% RPS studies for the same day.
- Observations / characteristics:
  - Higher average headroom as compared to the 14% RPS baseline and 14% RPS 4-hour forecast simulations for the same day.
  - Continued lower CT commitment than the 14% RPS 4-hour forecast simulation for the same day (which already was lower than the baseline).
  - Additional benefits observed are lower LMPs and fewer transmission constraints compared to the other 14% RPS, May 26 studies.
  - Still a high number of ramp constraints; quick change between generators ramping down and then ramping back up, which is expected due to significant and rapid changes in renewable energy.

CT Dispatch by Interval (14% RPS - May 26)



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Reduced Wind and Solar Forecast Error (20% LOBO – February 17)

- This sensitivity provided another look at lowering the uncertainty, by considering impact of reduced wind and solar forecast error (the forecast / actual differentials were reduced by 20%).
- Improved results, largely attributed to a better forward commitment resulting in higher average headroom.
- Observations / characteristics:
  - Several intervals with near-zero headroom
  - Overall, a significant improvement as compared to the corresponding sub-hourly analysis for February 17 in the baseline 20% LOBO case
  - Some real-time CT commitment, but less than other February 17 simulations
  - There were still some operationally challenging intervals with generator ramp limitations, low headroom, and CT commitment. However, no significant violations were observed.

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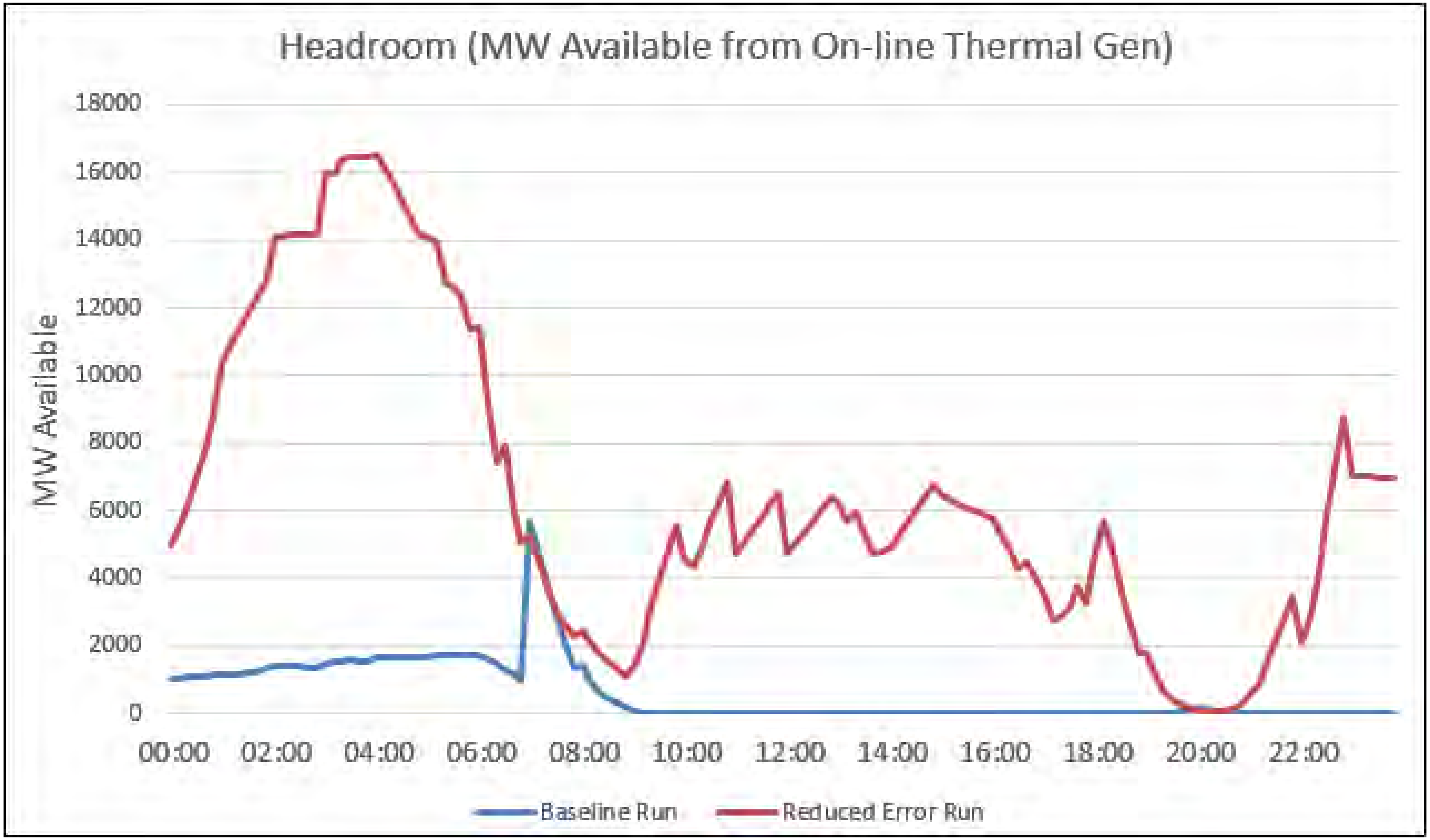
Headroom - MW Available from Thermal Generation (20% LOBO - February 17)



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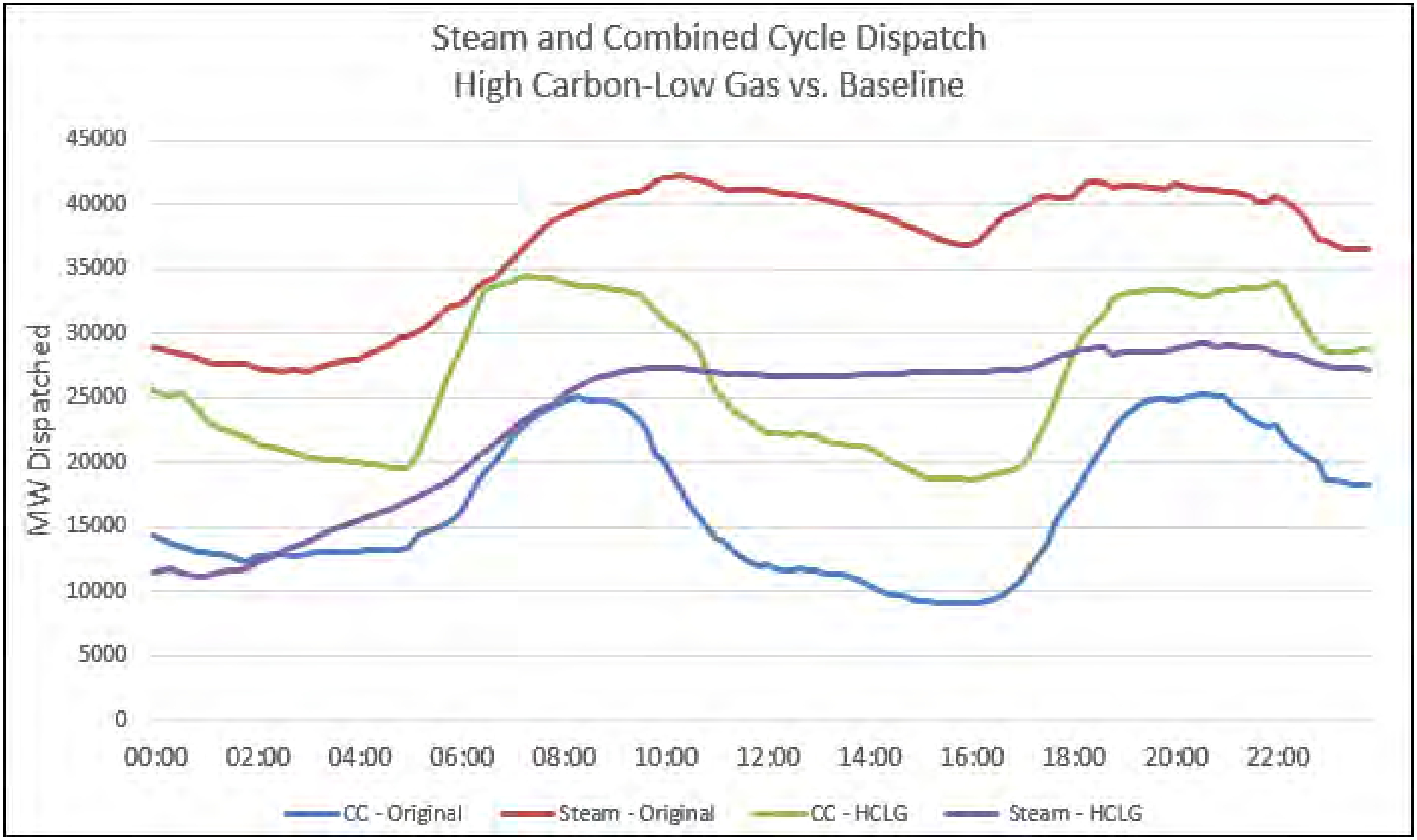
High Carbon Price, Low Gas Price (14% RPS – February 17)

- 14% RPS in February 17 solves with relative ease, but the low headroom proves to be a consistent feature in other scenarios with higher penetration levels.
- Likely the reason for the lower headroom is that fewer large steam turbines were committed in this case than in the original. This is a reasonable expectation under a high-carbon price scenario as coal plants will be more expensive.
- Observations / characteristics:
  - Low headroom on average and several sub-hourly intervals with zero headroom, and higher average LMPs, despite real-time CT commitment remaining the same.
  - Reserves required to cover energy shortage during two intervals, though the level of violation was minimal.
  - Results are not significantly different than the original 14% RPS simulation.

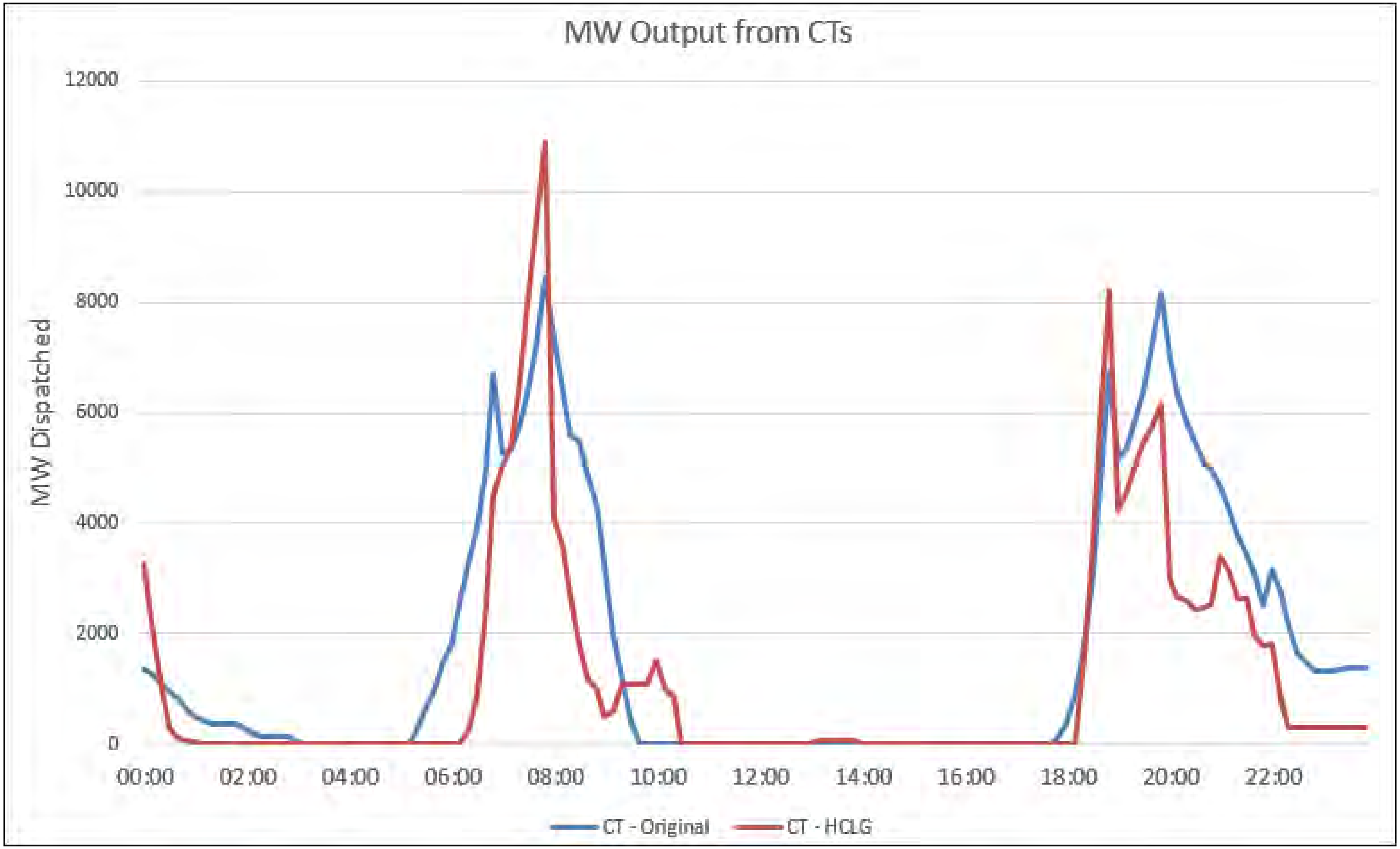
High Carbon Price, Low Gas Price (30% LOBO – February 17)

- This sensitivity considered the case of lower natural gas prices with higher (non-zero) carbon price at sub-hourly level for the 30% LOBO scenario.
- The main difference with the baseline 30% LOBO simulation is the type of thermal unit commitment. Under this sensitivity, more CCs and fewer steam turbines are committed.
- Observations / characteristics:
  - Several intervals with zero headroom
  - Less headroom and higher LMP than corresponding baseline 30% LOBO case
  - Significant real-time CT commitment in some intervals, but overall CT commitment is lower than corresponding baseline 30% LOBO case
  - Violated line rating on one transmission line to arrive at a solution

Steam/CC Dispatch by Interval (30% LOBO - February 17)



CT Dispatch by Interval (30% LOBO - February 17)



Conclusions/Recommendations

- Mid-Term Unit Commitment and Wind and Solar Forecast
  - Given the inherent uncertainty in day-ahead wind + solar forecasts, system operations can be improved if unit commitments are adjusted during the operating day when more accurate forecasts are available.
  - It is suggested that PJM consider addition of a mid-term re-commitment process (e.g., 4 hours-ahead) with updated wind and solar forecasts.
  - This will enable shifting some energy from CTs to other more-efficient resources (e.g., combined cycle plants that can start in a few hours).
  - The benefits of this practice would increase as wind and solar penetration increases.

Review of Industry Practice and Experience in the Integration of Wind and Solar Generation

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Investigation of Industry Practices

- This task investigated the current state of the art with variable generation integration, mostly focused on the United States but providing a few international examples where particularly relevant.
- The results are documented in a free-standing task report:
  - PJM Renewable Integration Study, "Task Report: Review of Industry Practice and Experience in the Integration of Wind and Solar Generation", Prepared by: Exeter Associates, Inc. and GE Energy, November 2012.

Investigation of Industry Practices

- The task was predominantly based on an extensive literature review with input from General Electric (GE) and PJM.
- Investigation considered a multitude of attributes, including:
  - Energy market scheduling
  - Visibility of distributed generation to grid operators
  - Energy imbalances
  - Reserves
  - Contingency reserves
  - Wind and solar forecasting
  - Consideration of variable generation as a capacity resource, and
  - Active power management of variable power generation.

GE Team's Views On The "Preferred Practices" In Integrating Wind And Solar Generation.

- Energy Market Scheduling
  - Sub-hourly scheduling and dispatch, for both internal (within-RTO and within-utility) and for scheduling on external interconnections with other balancing authorities, is a best practice.
- Visibility of Solar Distributed Generation
  - Install telecommunications and remote control capability to clusters of solar DG in PJM's service area. Alternatively, have distribution utilities install such capability and communicate data and generation to PJM.
  - Include solar in variable generation forecasting.
  - Account for the impacts of non-metered solar DG in load forecasting.
  - Follow and/or participate in industry efforts to reconcile provisions in IEEE-1547 and Low-Voltage Ride-Through Requirements.

Preferred Practices (Continued)

- Reserves
  - Consider separating regulation requirements into regulation up and regulation down if there is a shortage of regulation for certain hours, if there is a disproportionate need for a certain type of regulation (up or down), or if there is a desire to more finely tune regulation requirements.
  - Have operating reserve requirements set by season or by level of expected variable generation, instead of a static requirement that changes infrequently.
  - Use demand response to provide some reserves.
  - Consider using contingency reserves for very large but infrequent wind and solar ramps.
  - Require wind and solar generators to be capable of providing AGC.

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Preferred Practices (Continued)

- Wind and Solar Forecasting
  - Implement a centralized forecasting system for wind and utility-scale solar that offers day-ahead, very short-term (0-6 hours), short-term (6-72 hours), and medium or long-term forecasts (3-10 days).
  - Ensure that short-term wind and solar forecasting systems can capture the probability of ramps, or implement a separate ramping forecast.
  - Institute a severe weather warning system that can provide information to grid operators during weather events.
  - Monitor the use of confidence intervals and consider adjusting them periodically.
  - Integrate the wind and solar forecasts with load forecasts to provide a “net load” forecast.
  - Institute requirements for data collection from wind and solar generators that can be used to track forecast performance.

Preferred Practices (Continued)

- Intra-Day Unit Commitment
  - Consider establishing intra-day unit commitment, if one is not already in place, and incorporate short-term wind and solar forecasts.
- Look-Ahead Dispatch
  - Consider establishing a Look-Ahead Dispatch for very short time frames.
- Capacity Value of Wind and Solar
  - Conduct an ELCC study of wind and solar capacity value at regular intervals, and use them to calibrate or modify other approximate methods for calculating capacity values of wind and solar plants.
- Wind Ramps
  - Require wind generators to be equipped with control functions that can limit ramp rates.
- Frequency Response
  - Do not impose Frequency Response Requirements on wind Generators unless it is absolutely necessary.

Other Potential Preferred Practices

- Short-Term Dispatch and Scheduling Requirements for Wind
  - Consider Including Wind in Short-Term Dispatching and Scheduling
- Contingency Reserves and Variable Generation
  - Consider Using Contingency Reserves for Very Large but Infrequent Wind Ramps
- New or Revised Reserves
  - Consider Establishing a Slower Responding and Longer-Lasting Reserve to Cover Wind Ramps
  - Monitor Industry Initiatives to Acquire or Encourage More Flexible Reserves
- Integration Charges
  - Monitor Industry and Regulatory Discussions on Integration Charges
- Virtual Bidding
  - Do Not Rely Upon Virtual Bidding to Cover for Forecasting Errors

Task 4: Mitigation, Facilitation, Report (GE/PowerGEM) [15 Minutes]

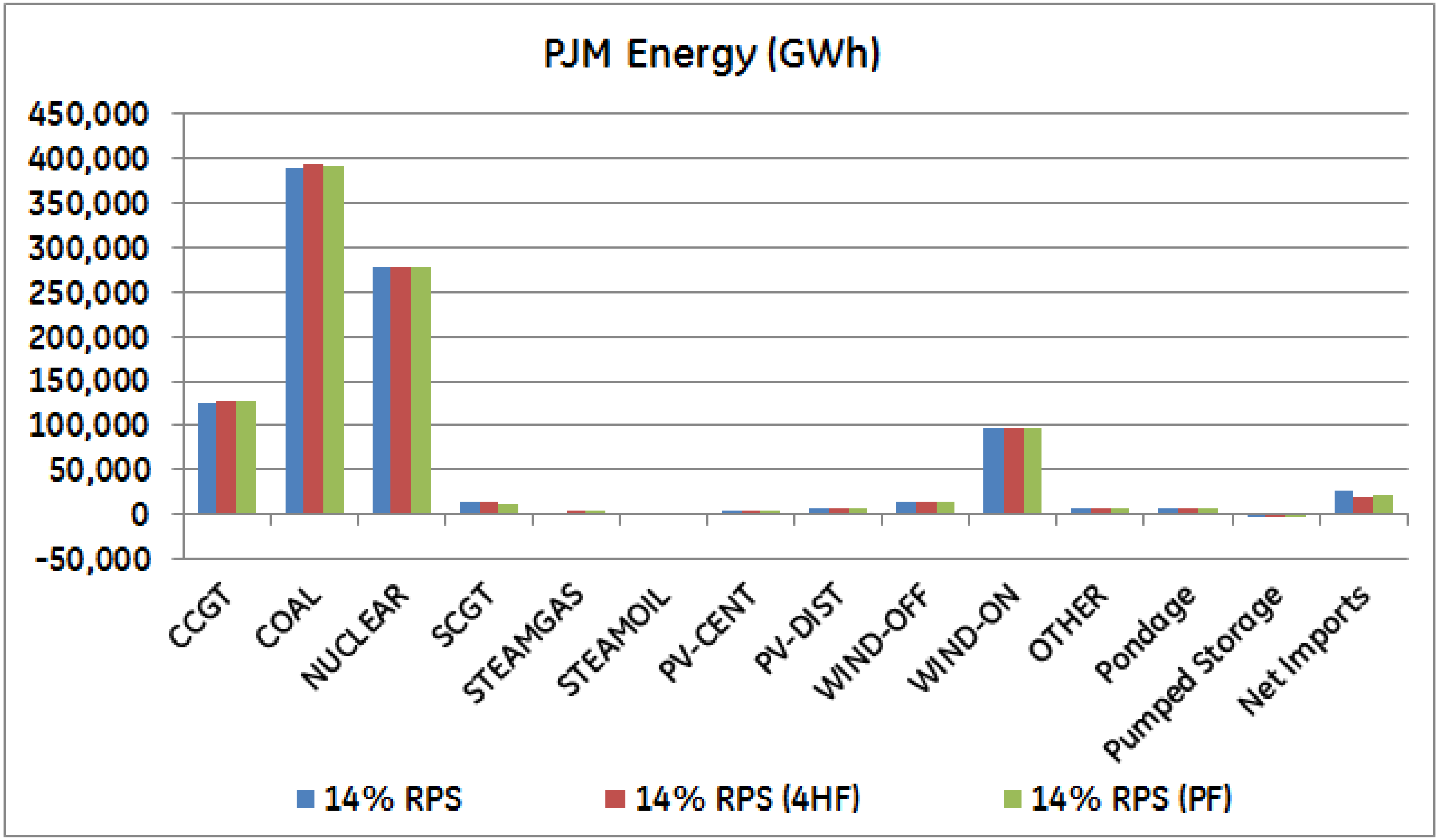
Mitigation Tasks Performed

- In performing this project, the GE Team has come to the conclusion that PJM's current energy scheduling practices already incorporates recommendations from previous renewable energy integration studies.
- Based on the above observations, it was agreed that the project team should perform the following simulations to see if additional mitigation measures were required:
- Hourly GE-MAPS Simulations:
  - 14% RPS, Forecast Improvement
  - 20% LOBO, Forecast Improvement
  - 30% LOBO, Energy Storage as Reserve
  - 30% LOBO, Impact of Cycling Costs
- 6 Sub-Hourly PROBE Simulations:
  - 30% LODO, June 18: Increased ramp rate

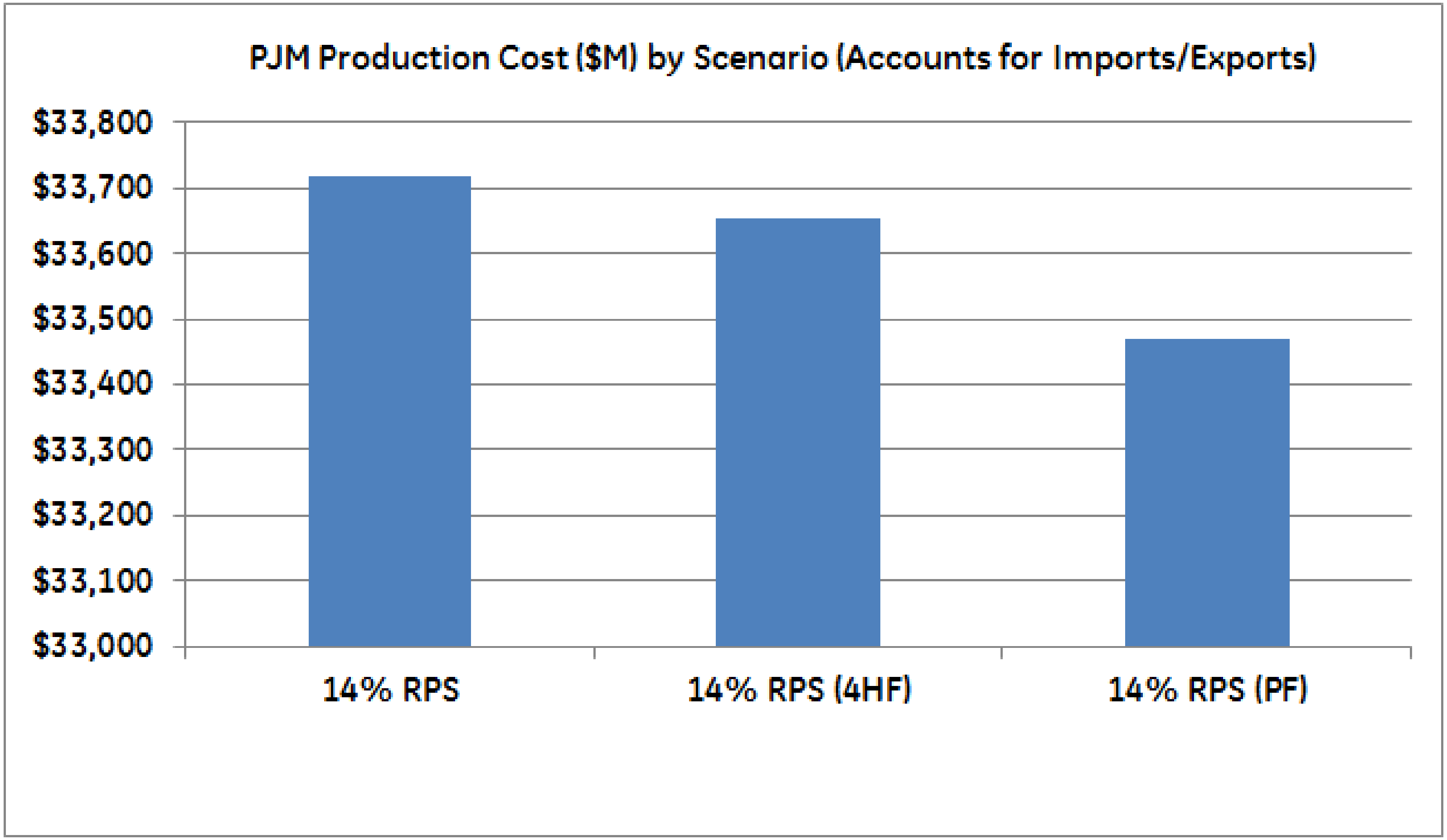
4-Hour Forecast & Perfect Forecast (14% RPS) Hourly GE-MAPS Sensitivity

- These two sensitivity analyses (i.e., 4-Hour Forecast and Perfect Forecast) with hourly GE MAPS simulation evaluated the impact of less uncertainty and reduced wind and solar forecast error and benefit of a mid-term unit commitment on the system operations and economics.
- Analysis was performed on the 14% RPS scenario, and the forecast improvement only applied to PJM and not the rest of EI.
- Observations / Characteristics:
    - Primary impact is shift from More Imports to More Internal PJM Generation.
    - Within PJM, compared to the original case, with the 4-Hour Forecast, generation of CCGT increased by 2.0 TWh, Coal increased by 4.7 TWh, SCGT decreased by 0.2 TWh, and Imports decreased by 6.7 TWh.
    - Within PJM, compared to the original case, with the Perfect Forecast, generation of CCGT increased by 1.6 TWh, Coal increased by 3.3 TWh, SCGT decreased by 1.5 TWh, and Imports decreased by 3.7 TWh.
    - The 4-Hour Forecast decreased PJM Production Costs by about $65M.
    - The Perfect Forecast decreased PJM Production Costs by about $250M.

4-Hour Forecast & Perfect Forecast
14% RPS – Energy Impact



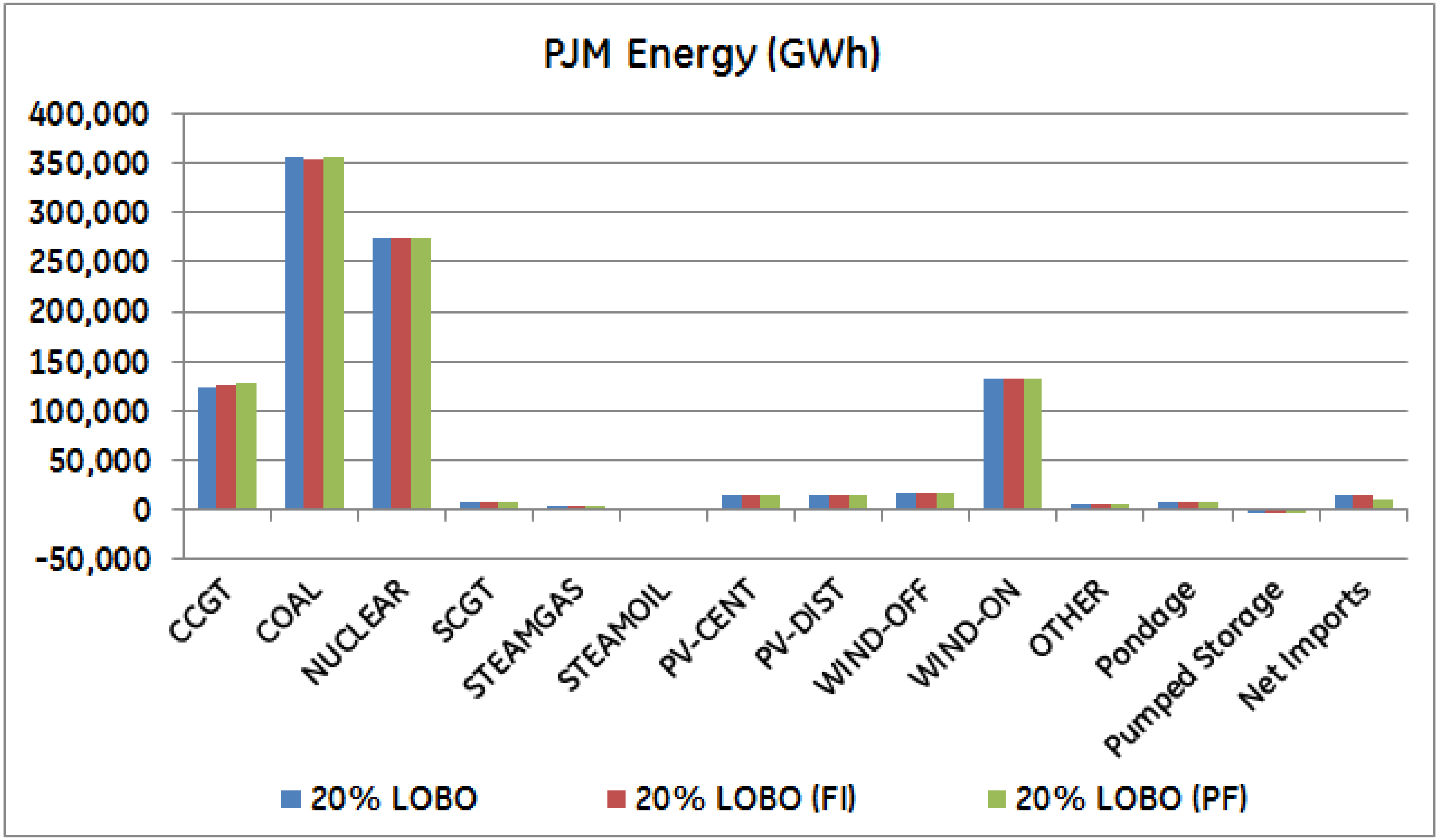
4-Hour Forecast & Perfect Forecast 14% RPS – Production Cost Impact



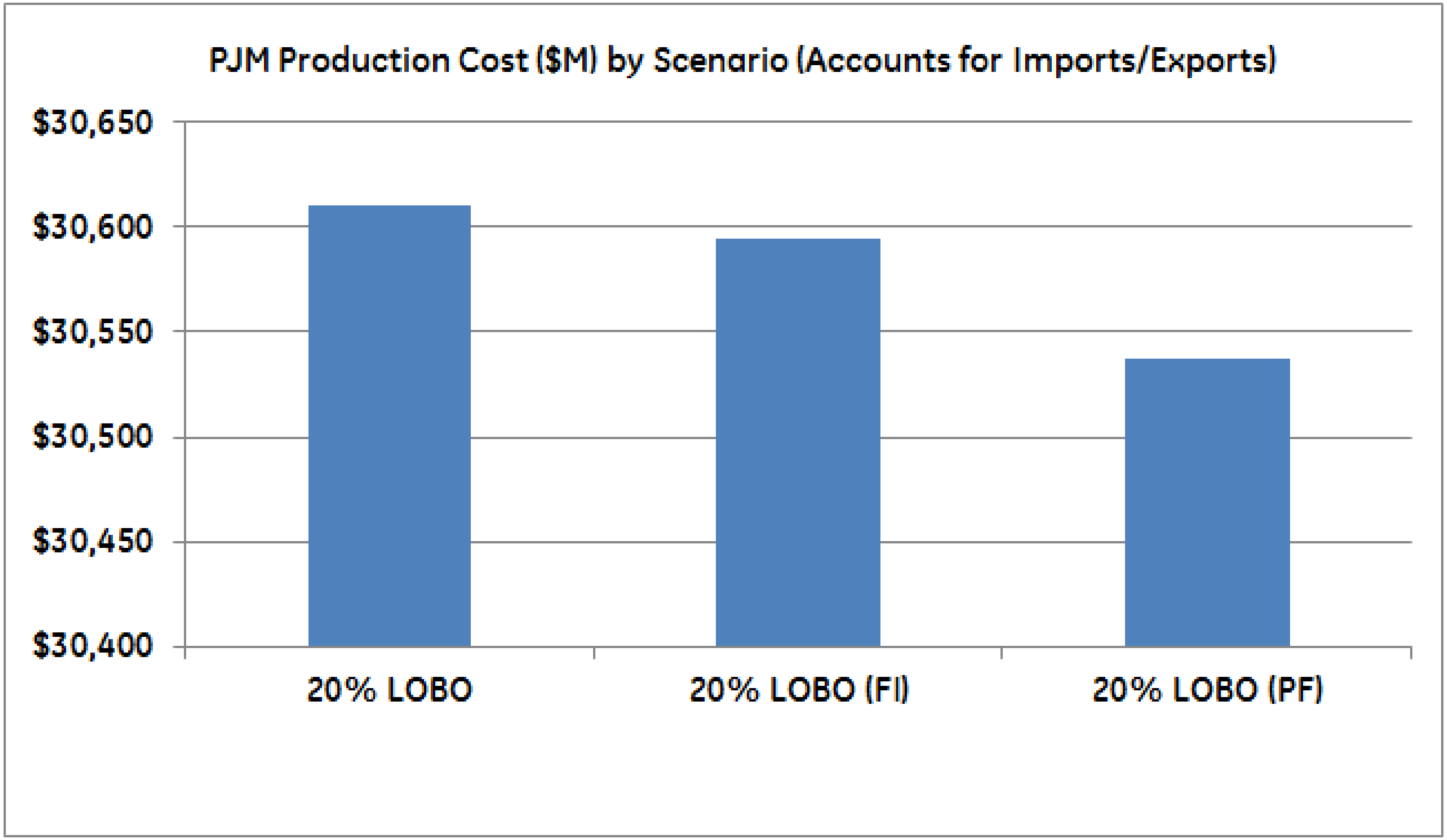
20% Forecast Improvement & Perfect Forecast (20% LOBO) Hourly GE-MAPS Sensitivity

- These two sensitivity analyses (i.e., 20% Forecast *Improvement in the day-ahead forecast* & Perfect Forecast) with hourly GE MAPS simulation evaluated the impact of less uncertainty and reduced wind and solar forecast error on the system operations and economics.
  - 20% Forecast Improvement is based on reducing hourly Forecast-Actual Delta by 20%. Analysis was performed on the 20% LOBO scenario, and the forecast improvement applied to all of the Eastern Interconnect.
- Observations / Characteristics:
  - Within PJM, compared to the original case, with the 20% Forecast Improvement, CCGT generation increased by 0.4 TWh, Coal decreased by 0.3 TWh, and Imports decreased by 0.2 TWh.
  - Within PJM, compared to the original case, with the Perfect Forecast, CCGT generation increased by 3.8 TWh, Coal increased by 0.3 TWh, and Imports decreased by 4.7 TWh.
  - The 20% Forecast Improvement decreased PJM Production Costs by about $15M, whereas the Perfect Forecast decreased PJM Production Costs by about $73M.

20% Forecast Improvement & Perfect Forecast 20% LOBO – Energy Impact



20% Forecast Improvement & Perfect Forecast 20% LOBO – Production Cost Impact



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Energy Storage as Reserve (500 MW and 1000 MW ES) (30% LOBO) Hourly GE-MAPS Sensitivity

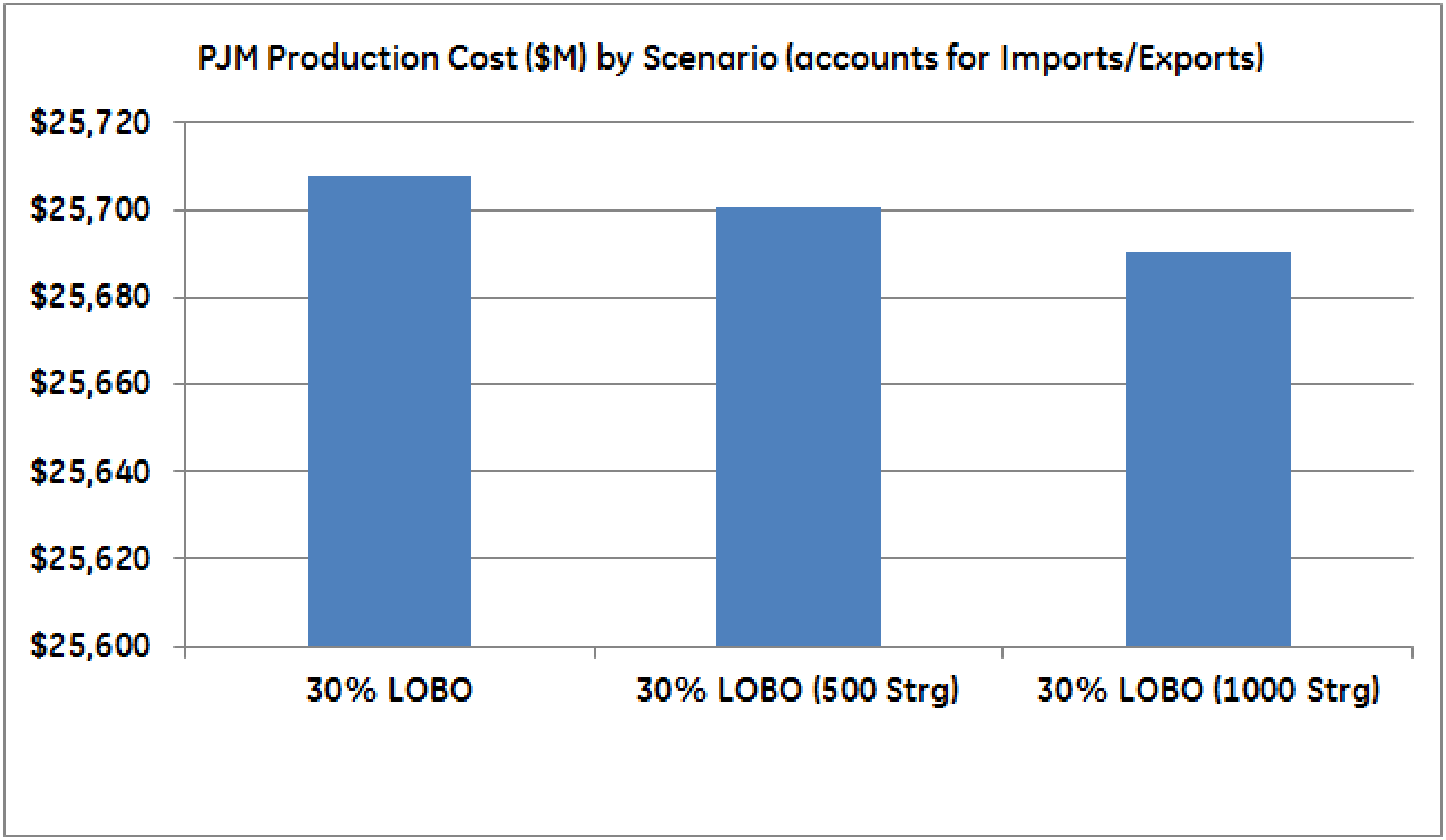
- These two sensitivity analyses with hourly GE MAPS simulation evaluated the impact of providing hourly reserve with Energy Storage (and freeing up equivalent amount of reserve set-aside by thermal generation) on the system operations and economics. In the simulation, the PJM reserve requirements were simply reduced by the equivalent amounts.
- Analysis was performed on the 30% LOBO scenario.
- Observations / Characteristics:
  - 500 MW or even 1000 MW ES are too small compared to the system size to make any significant impact on PJM LMPs.
  - ES for Reserve caused a small drop in PJM Total Production Cost:
    - $6.96M with 500 MW ES
    - $17.41M with 1000 MW ES
  - This translates into:
    - Production Cost Savings of 500 MW Storage = $1.59/MWh ($13.91/kW-Year),
    - Production Cost Savings of 1000 MW Storage of $1.99/MWh ($17.41/kW-Year)
    - Production Cost Savings of going from 500 MW to 1000 MW Storage is $2.39/MWh

Note on Energy Storage Value

It should be noted that Energy Storage provides more value to the grid than the specific application examined here.

- Energy Storage is successfully participating in the PJM frequency regulation market.
- The analysis does not evaluate the ability to mitigate the variability of wind and solar - but only considers Energy Storage as a substitute for thermal resources in providing a specific amount of regulation reserve and its impact in lowering production costs.
- The results of this analysis are specific to the particular application of Energy Storage examined, and do not represent a complete evaluation of Energy Storage benefits in PJM.

Energy Storage as Reserve (500 MW & 1000 MW ES) 30% LOBO – Production Cost Impact



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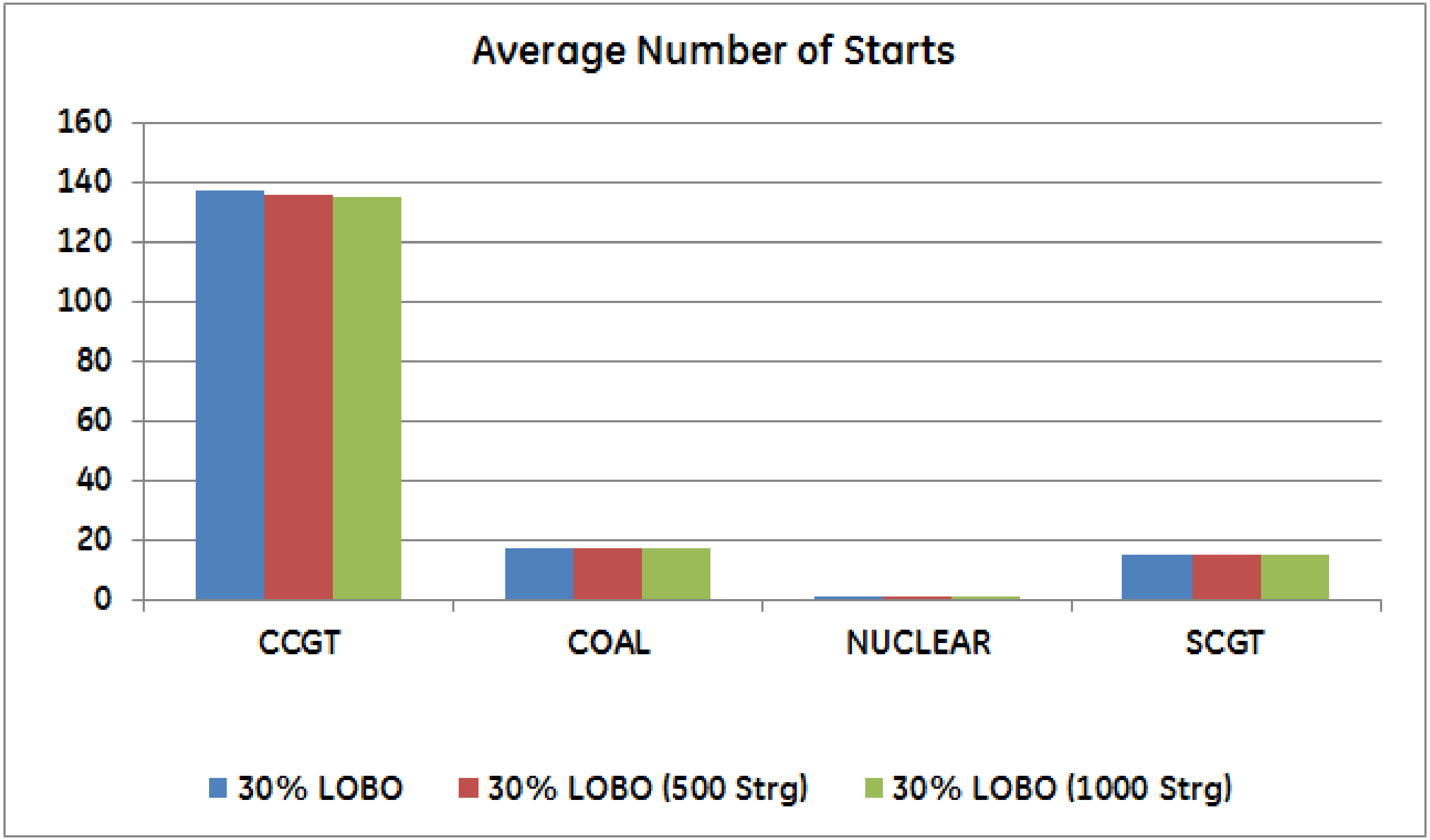
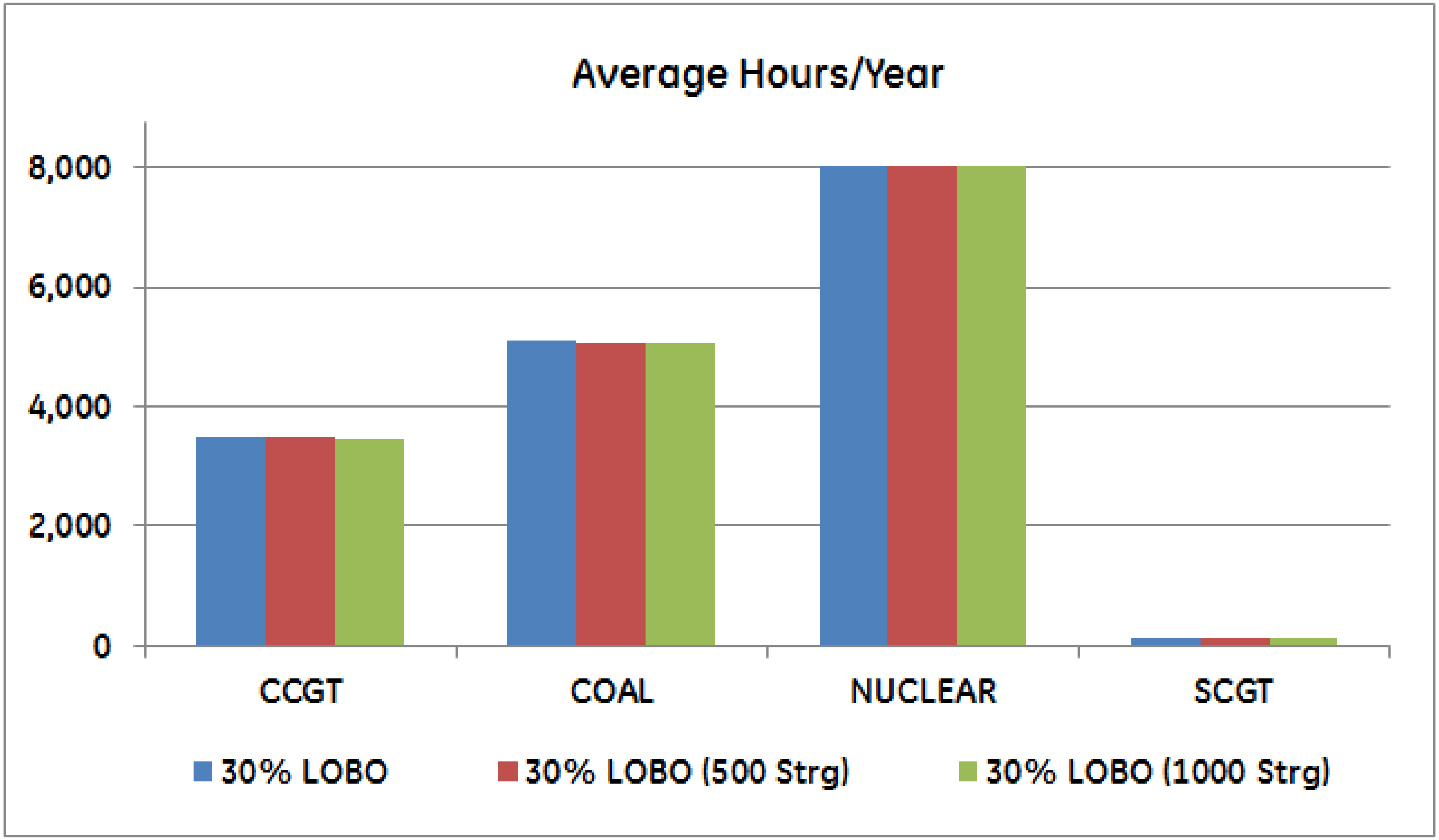
Energy Storage for Reserves Lowered Average Number of Starts of CCGTs



But Energy Storage for Reserves did not impact CCGTs' Average Hours/Year

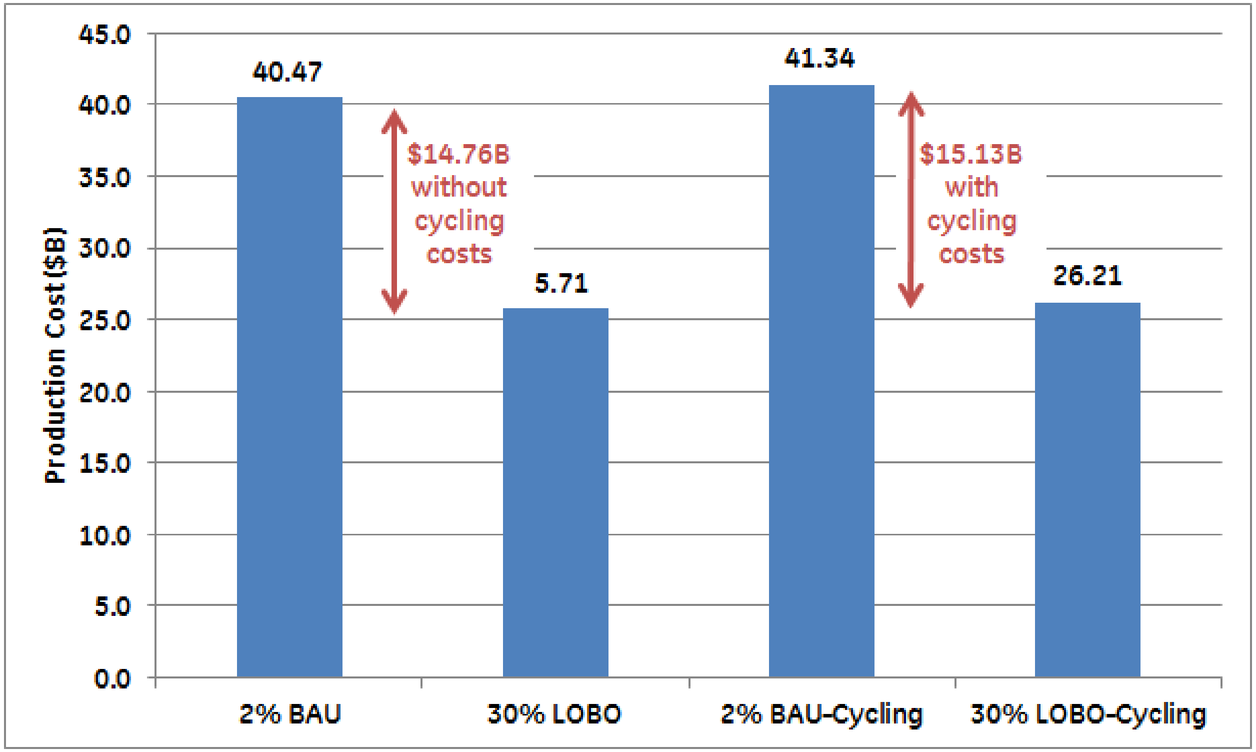


Accounting for Power Plant Cycling Costs (30% LOBO) Hourly GE-MAPS Sensitivity

- This sensitivity analysis with hourly GE MAPS simulation evaluated the impact of including the power plant cycling costs as a $/MWh adder to the each plant type VOM (provided by Intertek AIM), using the data from the Power Plant Cycling Cost Analysis of this study.
- Analysis was performed on the 30% LOBO scenario.
- Observations / Characteristics:
  - Total PJM Production Costs increased by $1.474B
  - Going from 2% BAU to 30% LOBO Production Costs was reduced by 14.763B.
  - Hence the Cycling Costs when accounted for as VOM adders in the analysis, reduces by about 10% the reduction in Production Cost of 30% LOBO relative to 2% BAU scenarios.

Impact of Cycling Effects on Total Production Costs for 2% BAU and 30% LOBO Scenarios

- The two bars on the left of the figure show the total production costs without considering the “extra” wear-and-tear duty imposed by increased unit cycling.
- The increased renewables in the 30% scenario reduce annual PJM production costs by $14.76B.
- If the VOM costs due to cycling are included in the calculation (the right-side bars), the increased renewables in the 30% scenario reduce annual PJM production costs by $15.13B.
- The cycling costs increase the annual PJM production costs by $0.37B ($370M), or about 2%.



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Mitigation Study: Sub-Hourly Simulation of Increased Ramp Rates

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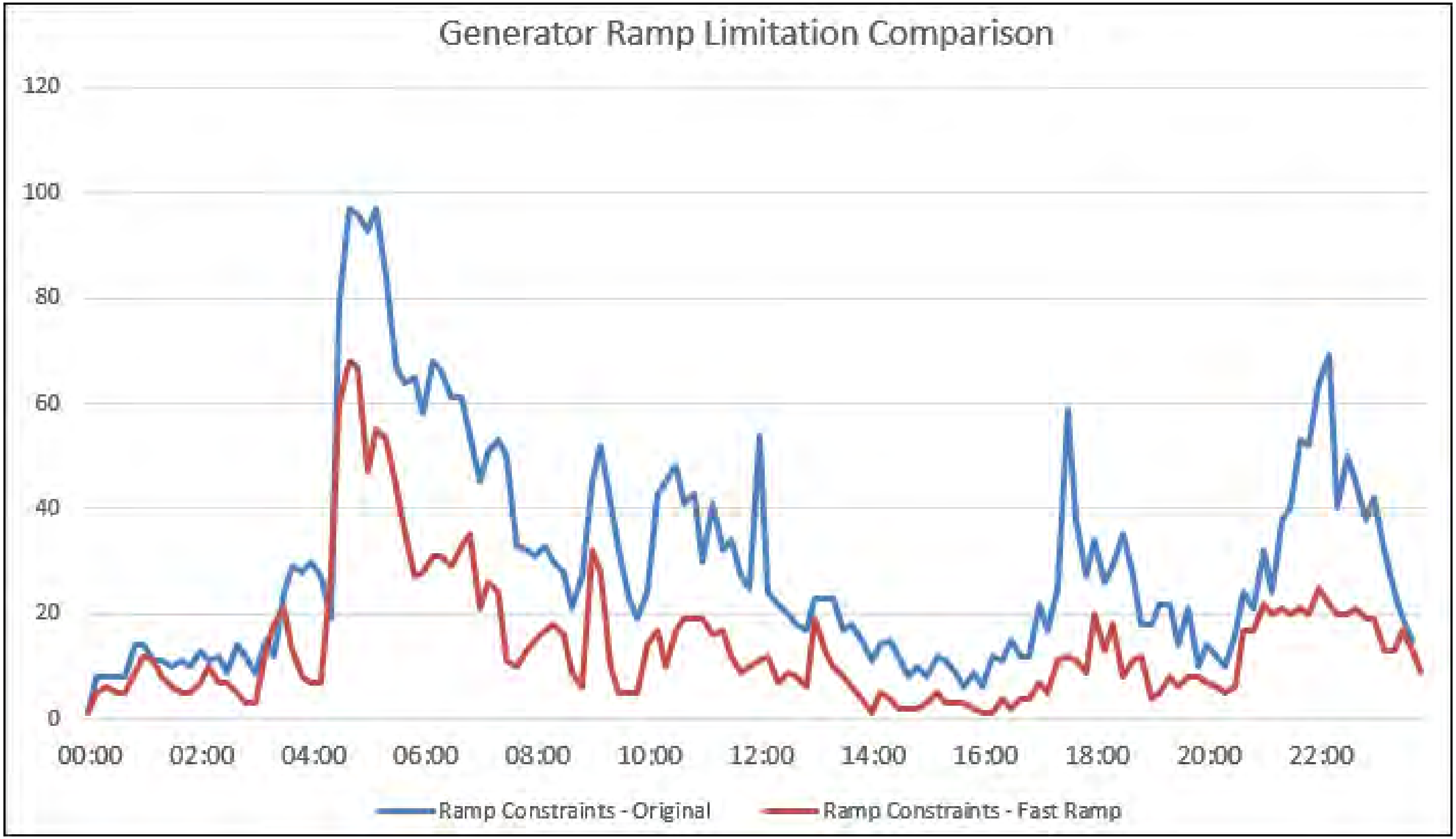
Increased Ramp Rate
30% LODO – June 18

- This sub-hourly sensitivity considers how faster ramp rates may improve real-time operations, considering that ramp rates were frequently observed as a limiting factor in most sub-hourly simulations.
- Observations / Characteristics:
  - A 51% reduction in ramp constrained generation
  - Fewer CTs committed
  - Lower LMPs and fewer transmission constraints
  - More operating flexibility

Number of Ramp-Constrained Units per 10-minute Interval (30% LODO - June 18)



Key Findings: Mitigations

- Further Support for Mid-Term Commitment & Better Wind/Solar Forecast
  - Addition of a mid-term commitment (e.g., 4 hours-ahead) with updated wind and solar forecast will allow for use of more accurate wind and solar forecasts in a time frame when commitments from intermediate units can still be adjusted, resulting in significantly less CT commitment in real-time.
- Benefits of Energy Storage to Provide Reserve
  - Reduction in regulation reserve requirements by using Energy Storage caused a small drop in PJM total production cost. These results should not be generalized, since we did not evaluate the benefits of the full range of service offerings of energy storage in PJM.
- Power Plant Cycling
  - Cycling Costs when accounted for as VOM adders reduces by about 10% the reduction in Production Costs of 30% LOBO relative to 2% BAU scenarios.
- Improved Ramp Rate
  - Improving Ramping of large Coal Plants would result in reduction in ramp constrained generation, fewer CTs committed, lower LMPs, less congestion, and more flexible operations.

Discussion of Key Findings and Recommendations and Topics for Future Study (PJM/GE) [15 Minutes]

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Key Findings and Recommendations

Key Findings and Recommendations were presented earlier.

Topics for Future Study

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Topics for Future Study

- Impacts of Reduced Energy Revenues for Conventional Power Plants
  - It is suggested that PJM investigate the potential consequences of reduced capacity factors and energy revenues on its conventional generation fleet.

- Flexibility Improvement for Conventional Power Plants
  - It is suggested that PJM investigate possible methods that could be applied to existing units with limited ramping or cycling capabilities.

- Expanding System Flexibility through Active Power Controls on Wind and Solar Plants
  - It is suggested that PJM investigate how wind and solar plants could contribute to frequency response, and work towards interconnection requirements that ensure PJM will continue to meet its grid-level performance targets.

Thank You!

Appendix A: Database Assumptions

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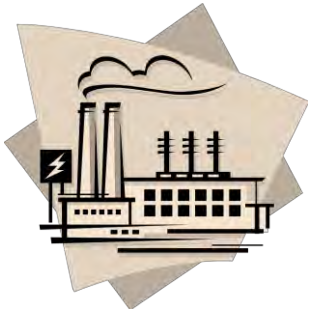
Project Team

- GE Energy Consulting – overall project leadership, production cost and capacity value analysis
- AWS Truepower – development of wind and solar power profile data
- EnerNex – statistical analysis of wind and solar power, reserve requirement analysis
- Exeter Associates – review of industry practice/experience with integration of wind/solar resources
- Intertek Asset Integrity Management (Intertek AIM), formerly APTECH – impacts of increased cycling on thermal plant O&M costs and emissions
- PowerGEM – transmission expansion analysis, simulation of sub-hourly operations and real-time market performance

Key Assumptions

- Entire Eastern Interconnect system is simulated
- Renewable plants are connected to higher voltage busses
- Remaining PJM coal plants are assumed to have emissions control technology
- Renewable resources are curtailed when dispatch will impact nuclear operation
- Only primary fuel is modeled
- Existing operating reserve practice is used for reference case, statistical analysis is used to modify reserves for others
- 2026 run year uses 2006 load and renewable hourly shapes.
- 2026 data are updated based on PJM input on coal retirement / gas repower and new builds

Thermal Generation Expansion Philosophy



- Proposed Approach Based on Past Experience:
  - Thermal Generation Expansion Plan in all of the scenarios is set to be the same as the expansion plan of the Base Case Scenario (i.e., 2% BAU)
  - This approach provides a level playing field and minimize results variability attributable to thermal generation

- How Much Thermal Capacity to Add?
  - Total Capacity in each region should meet the Annual Installed Reserve Margin (% of Annual Peak Load)
  - Reserve Margin Targets: 15.6% of Annual Peak Load

$$\boxed{\textbf{\textit{Reserve Margin}} = \frac{[\textbf{\textit{Capacity}} + \textbf{\textit{Firm Net Imports}} - \textbf{\textit{DSM}}]}{\textbf{\textit{Peak Demand}}}}$$

Generation Expansion Planning Process and Retirements

- Two main types of generic Candidate Plants were selected:
  - A future Combined Cycle Gas Turbine (CCGT) Type
  - A future Single Cycle Gas Turbine (SCGT) Type
- In 2% BAU Scenario, added an initial set of CCGTs & SCGTs to meet annual reserve margin target.
- Ran GE MAPS iteratively to refine SCGT and CCGT mix to achieve the desired capacity factors.
- Technology choice (SCGT vs. CCGT) was based on resulting utilization:
  - Capacity Factor for CCGT units > 30%
  - Capacity Factor for SCGT units < 10%
  - Unit locations based on proposed project sites (interconnection queues)
- Retirements were based on information provided by PJM.

Renewable Energy Penetration in the rest of the Eastern Interconnection

- Rest of EI does not grow its overall renewable penetration as quickly as PJM

- Eastern Wind Integration and Transmission Study (EWITS) Scenario 2 (20% Hybrid with Offshore) used as guide to determine allocations to other NERC Regions

EWITS Executive Summary and Project Overview Table 1

TABLE 1. TOTAL AND OFFSHORE WIND IN THE SCENARIOS

Region	Scenario 1 20% High Capacity Factor, Onshore		Scenario 2 20% Hybrid with Offshore		Scenario 3 20% Local, Aggressive Offshore		Scenario 4 30% Aggressive On- and Offshore	
	TOTAL (MW)	Offshore (MW)	Total (MW)	Offshore (MW)	Total (MW)	Offshore (MW)	Total (MW)	Offshore (MW)
MISO/ MAPP[a]	94,808		69,444		46,255		95,046	
SPP	91,843		86,666		50,958		94,576	
TVA	1,247		1,247		1,247		1,247	
SERC	1,009		5,009	4,000	5,009	4,000	5,009	4,000
PJM	22,669		33,192	5,000	78,736	39,780	93,736	54,780
NYISO	7,742		16,507	2,620	23,167	9,280	23,167	9.280
ISO-NE	4,291		13,837	5,000	24,927	11,040	24,927	11,040
TOTAL	223,609	0	225,902	16,620	230,299	64,100	337,708	79,100

[a] *MAPP stands for Mid-Continent Area Power Pool.*

PJM and EI Renewable Energy Penetration for Each Scenario

Scenario	PJM % RE	EI % RE
Base	14%	10%
Low Offshore	20%	15%
High Offshore	20%	15%
High Solar	20%	15%
Low Offshore	30%	20%
High Offshore	30%	20%
High Solar	30%	20%

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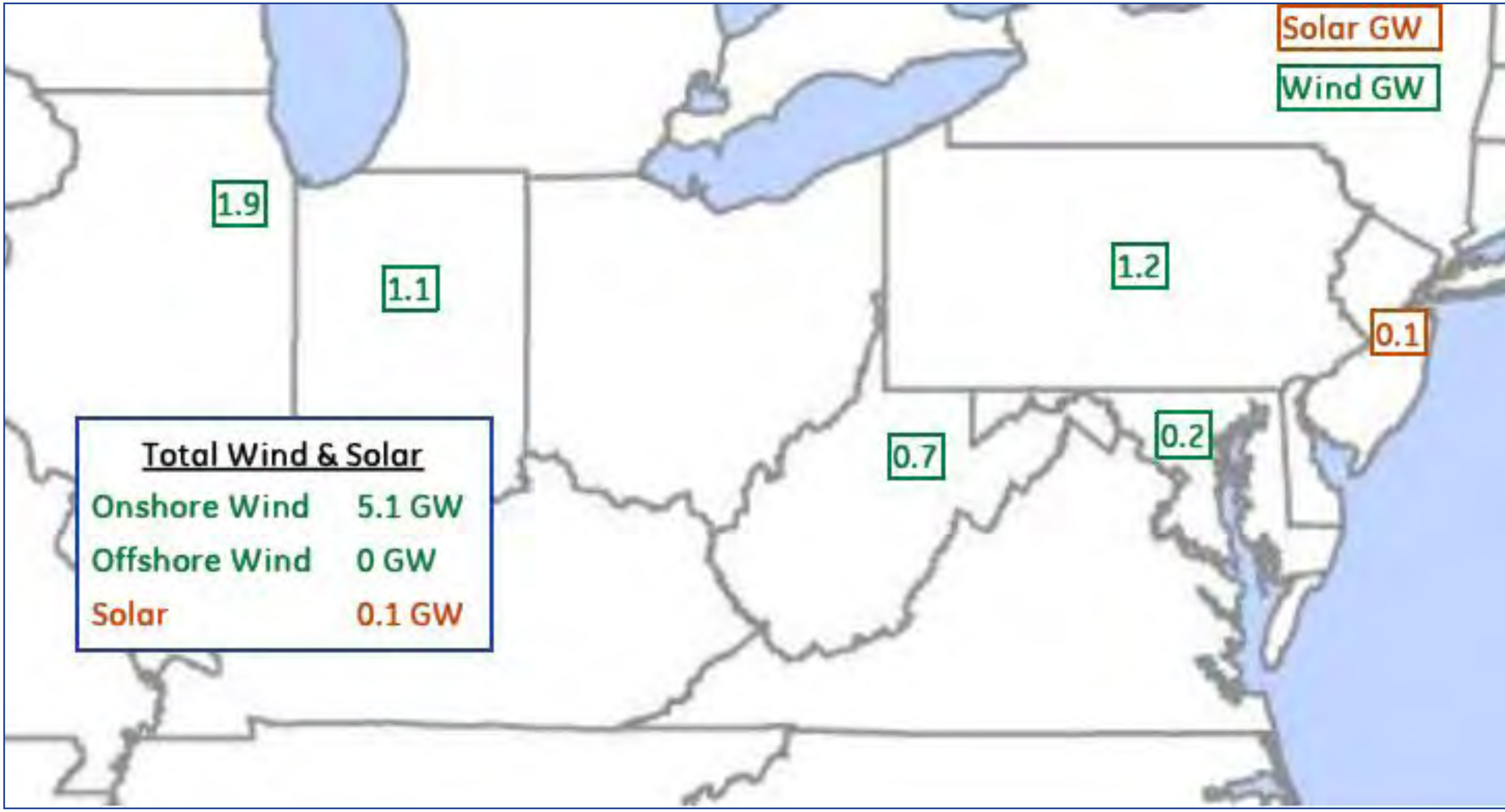
Scenario Development

- 20% and 30% Cases include wind & solar sites selected in the Base Case
  - Low Offshore, Best Sites Onshore
    - Incremental onshore &offshore wind added using best sites (Best Capacity factors)
    - NJ, DE, MD, NC, VA only have offshore sites
  - Low Offshore, Dispersed Onshore
    - Incremental onshore wind is added in IL, IN, OH, WV, PA
    - Incremental Onshore wind is added to the remaining states proportional to the ratio of PJM portion of the state load energy to the total PJM load energy
    - Incremental Offshore wind is added using the best sites (Best Capacity factors)
    - NJ, DE, MD, NC, VA only have offshore sites.
  - High Offshore , Best Sites Onshore
    - Incremental Offshore & Onshore wind is added in best sites (Best Capacity factors)
    - NJ, DE, MD, NC, VA only have offshore sites
  - High Solar, Best Sites Onshore
    - Solar Selection Criteria is followed
    - Incremental Offshore & Onshore wind added in best sites (Best Capacity factors)
    - NJ, DE, MD, NC, VA only have offshore sites.

2% BAU Scenario



Note: Dots indicate wind plant sites; Solar resources are not shown.

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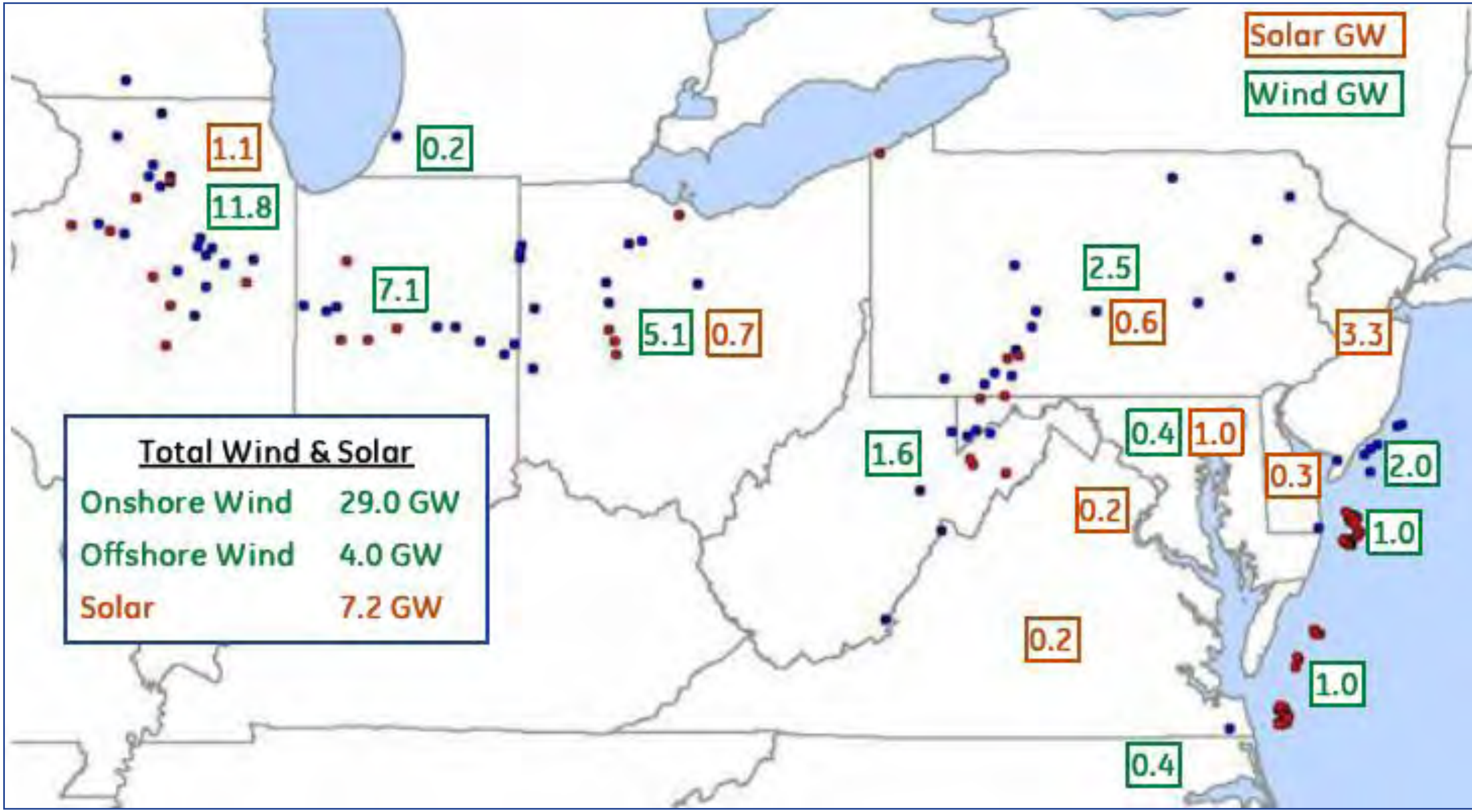
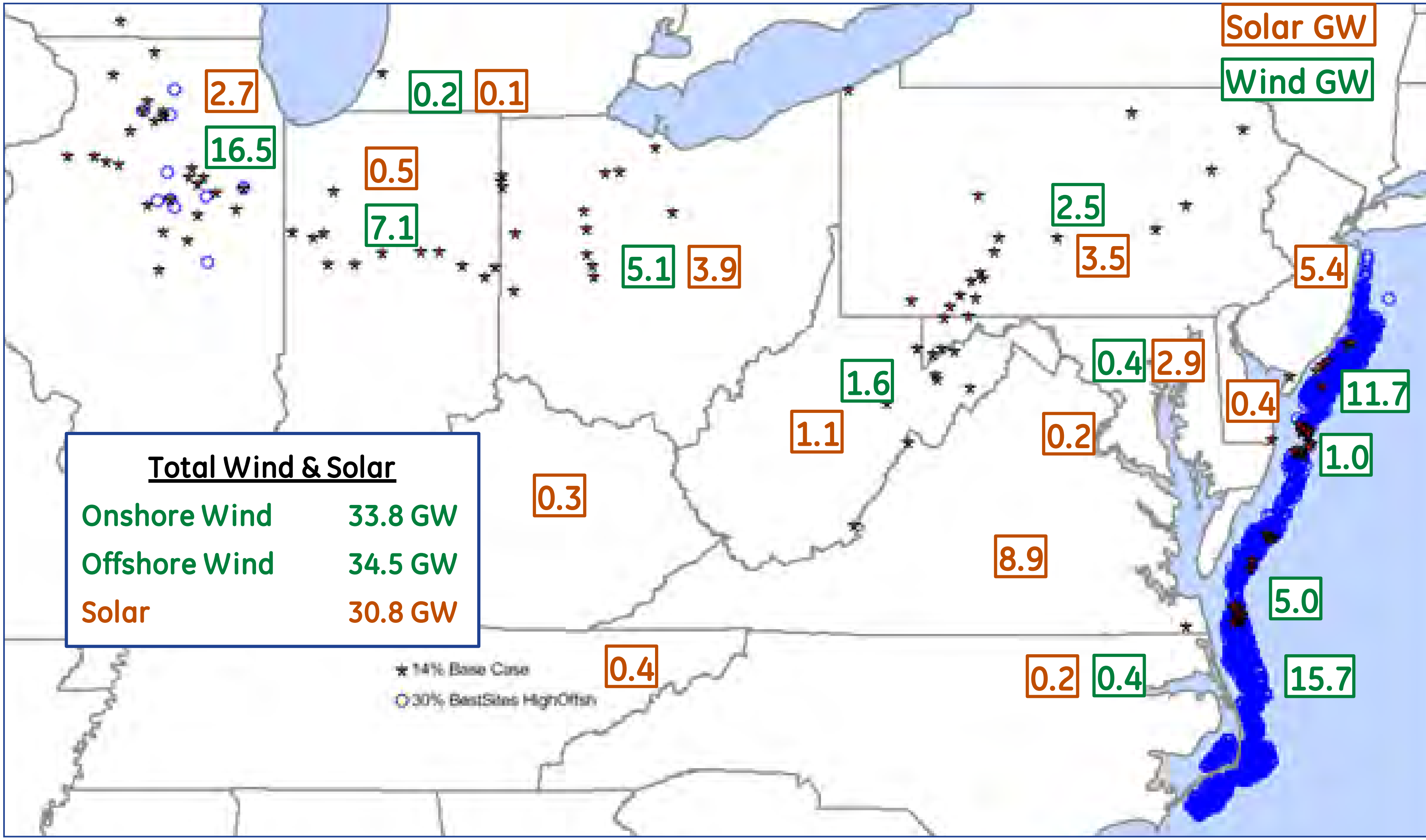
14% RPS Scenario



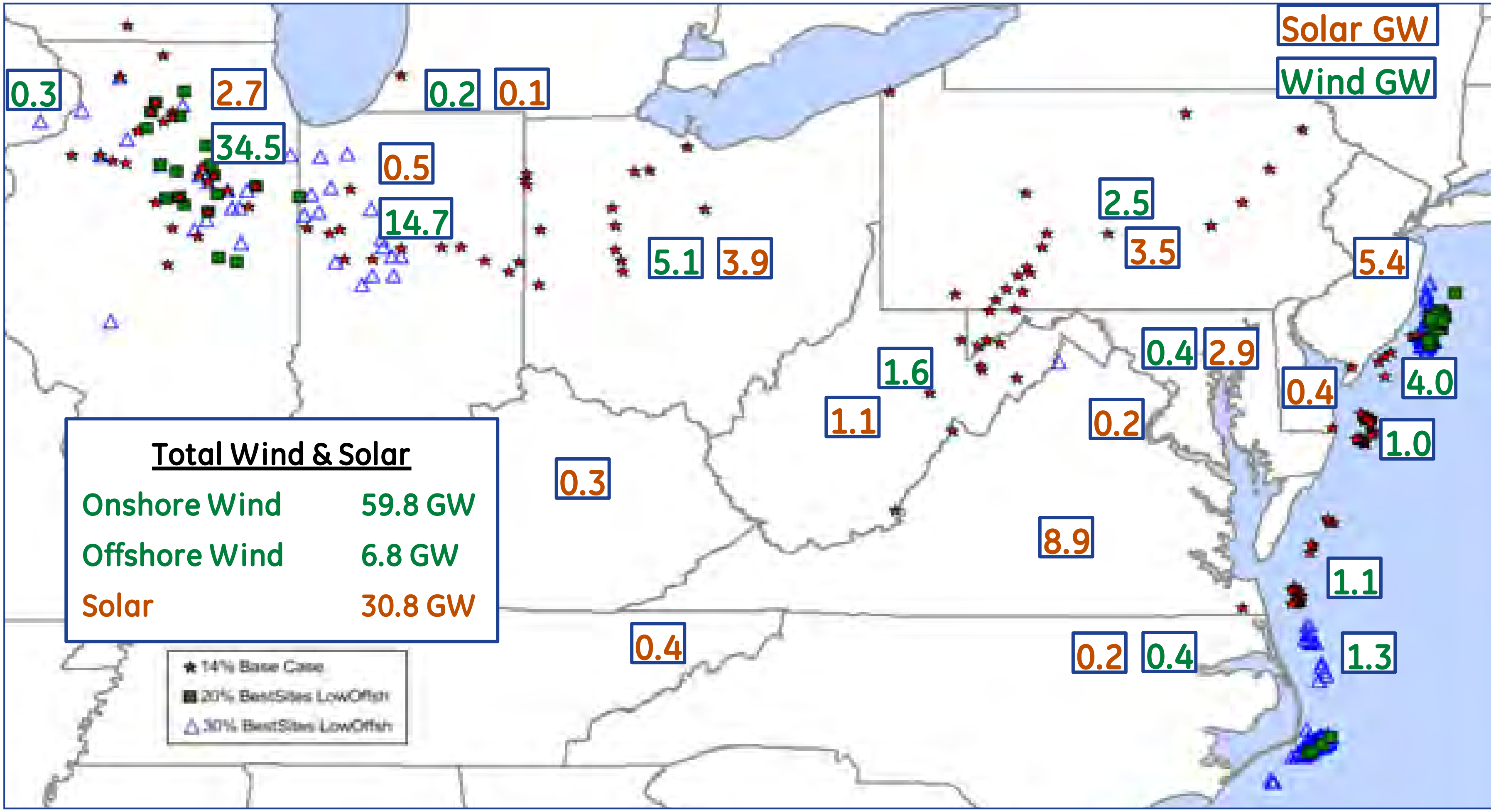
Note: Dots indicate wind plant sites; Solar resources are not shown.

30% High Offshore with Best Onshore Wind



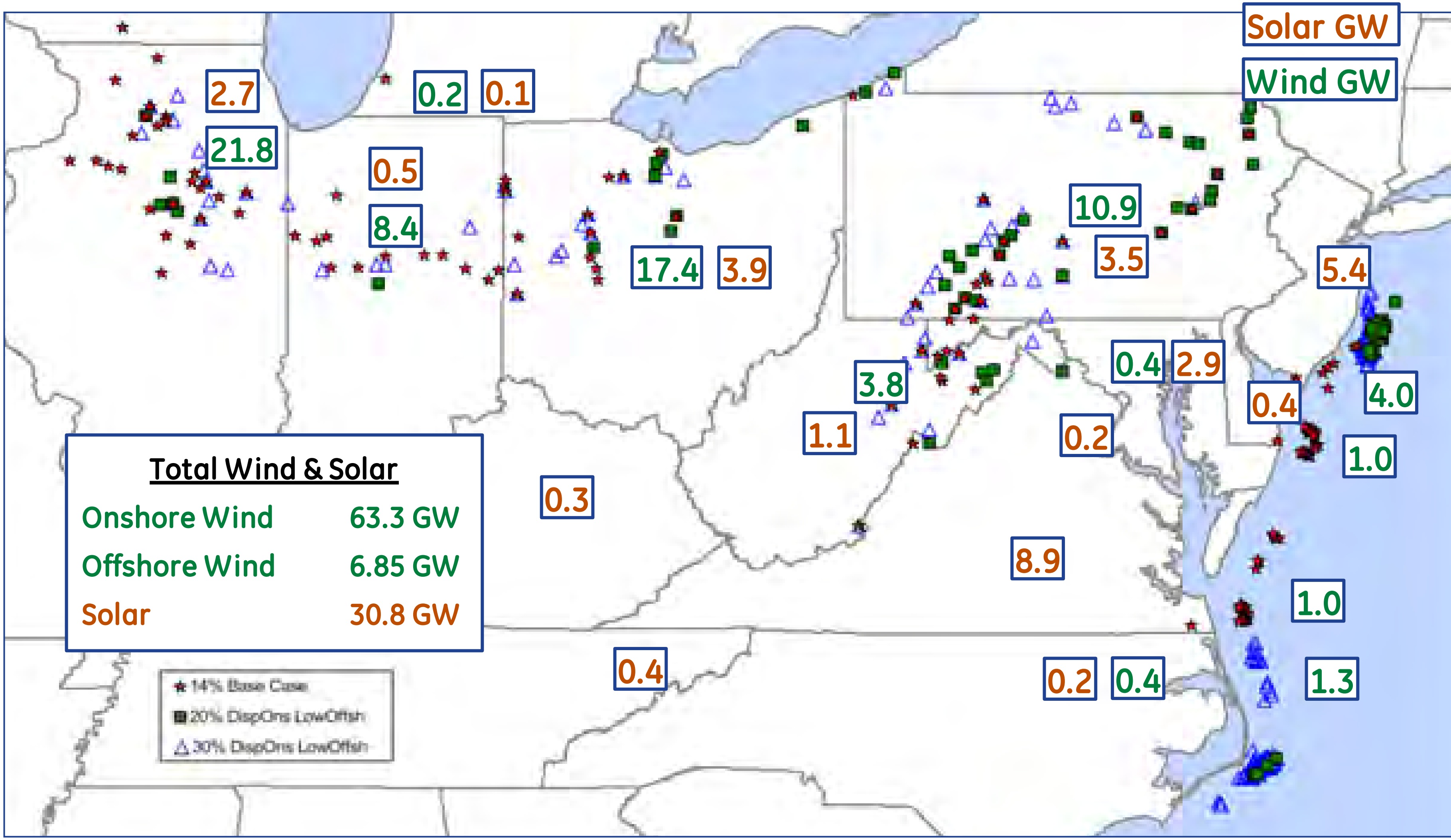
Note: Dots indicate wind plant sites; Solar resources are not shown.

30% Low Offshore with Best Sites Onshore



Note: Dots indicate wind plant sites; Solar resources are not shown.

30% Low Offshore, Dispersed Sites Onshore



Note: Dots indicate wind plant sites; Solar resources are not shown.

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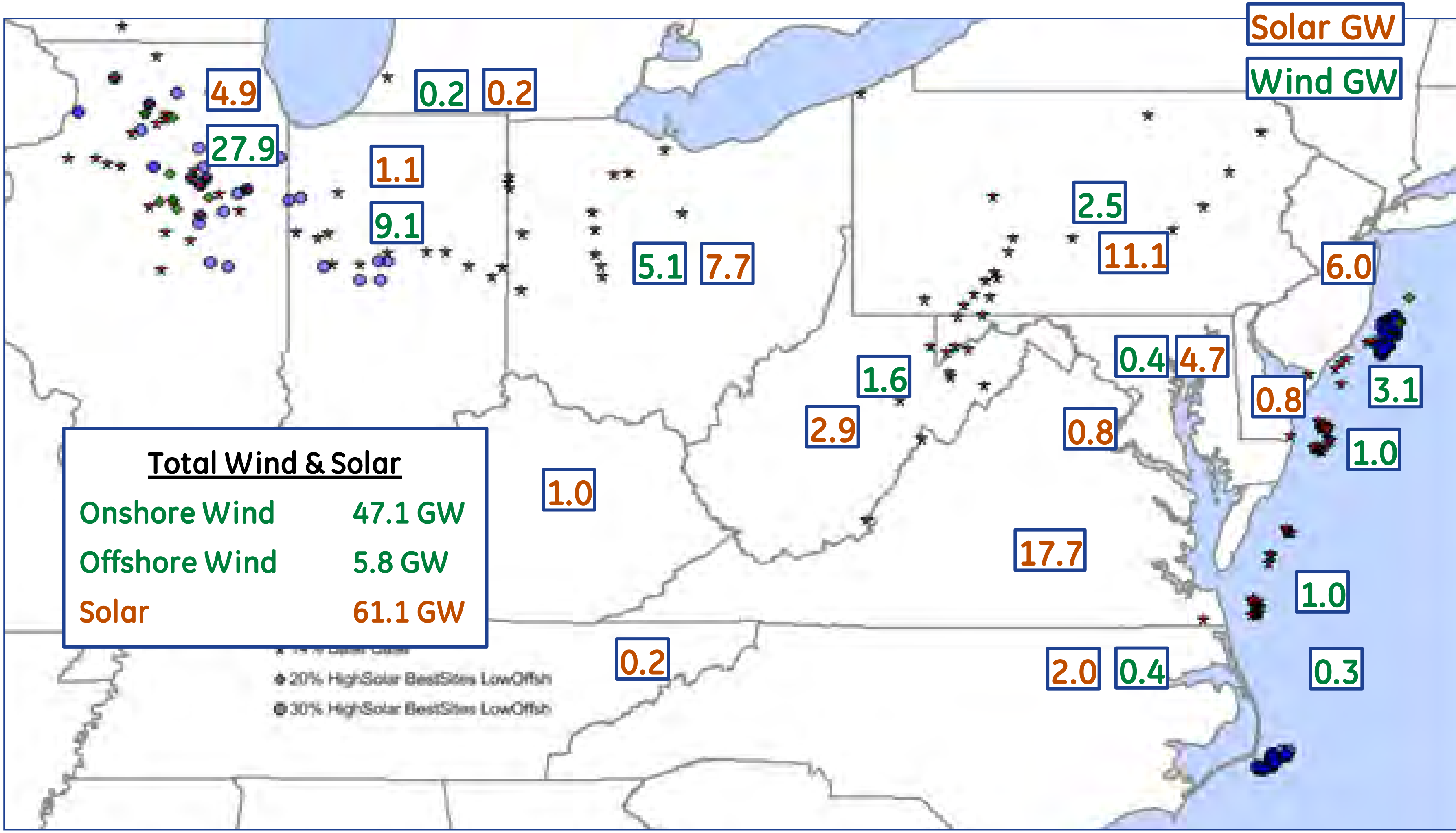
30% High Solar with Best Wind Sites Onshore



Note: Dots indicate wind plant sites; Solar resources are not shown.

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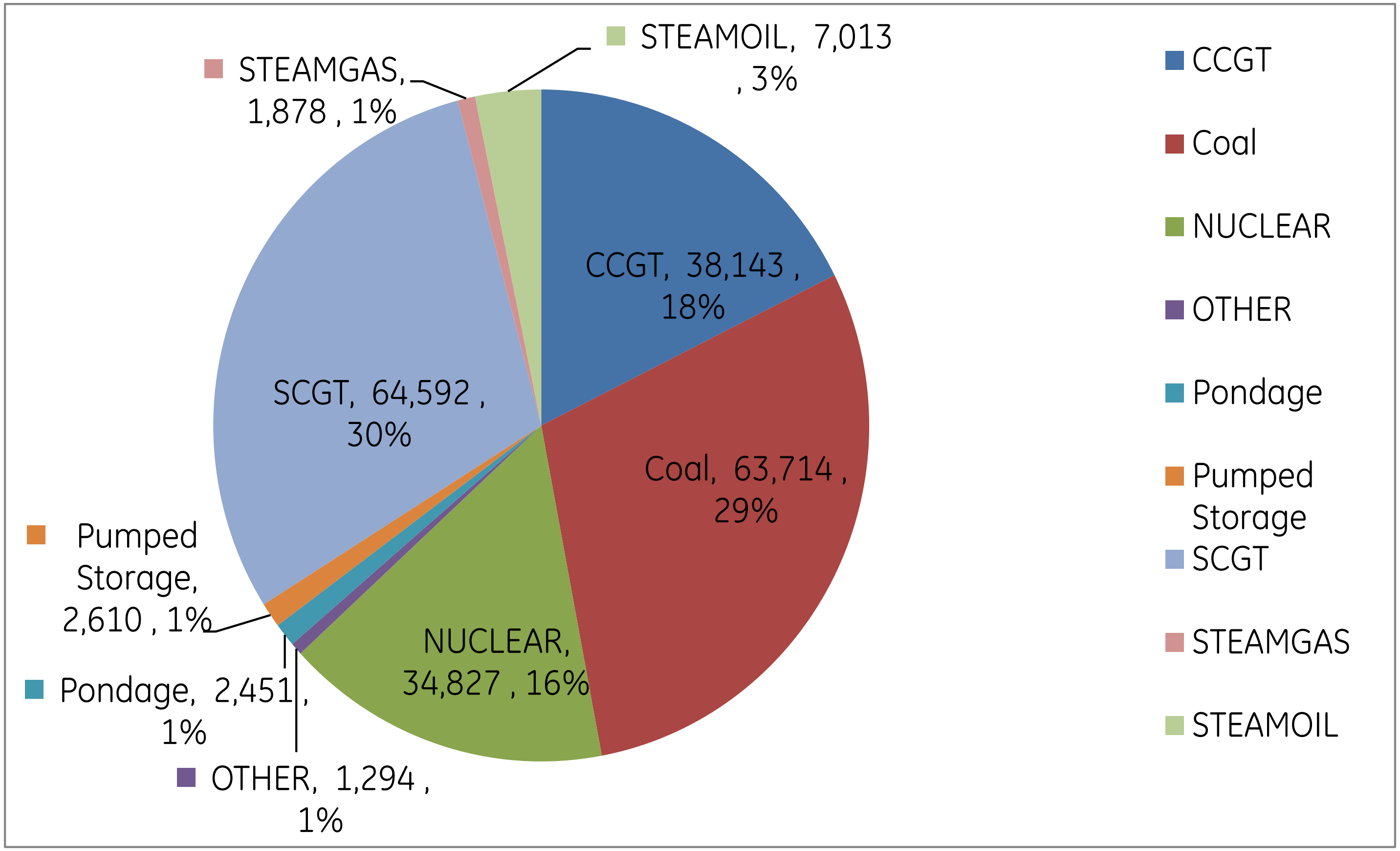
Installed Capacity in 2% BAU Excluding Wind and Hydro in Year 2026.



The chart includes 35 GW of new SCGT and 6 GW of new CCGT capacity over the existing capacity in order to meet the 2% BAU scenario 2026 planned reserve margin.

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Summary of Forecasted Fuel Prices for Study Year 2026

Fuel Type	Nominal Price	Source	Comments
Natural Gas	$8.02/MMBtu	EIA 2012 Energy Outlook	At Henry Hub; Regional basis differentials provided by PJM
Coal	$3.51/MMBtu	EIA 2012 Energy Outlook	Adjusted to reflect regional price differences ($1.15 to $6.08) per Ventyx historical usage data.
Nuclear	$0.75/MMBtu	Ventyx Energy Velocity Forecast	
Residual No.2 Oil	$15.04/MMBtu	Energy Velocity NYMEX Forecast	Adjusted to include monthly variation patterns ($14.92 to $15.20)
LS No.2 Diesel	$22.56/MMBtu	Energy Velocity NYMEX Forecast	Adjusted to include monthly variation patterns ($22.37 to $22.79)

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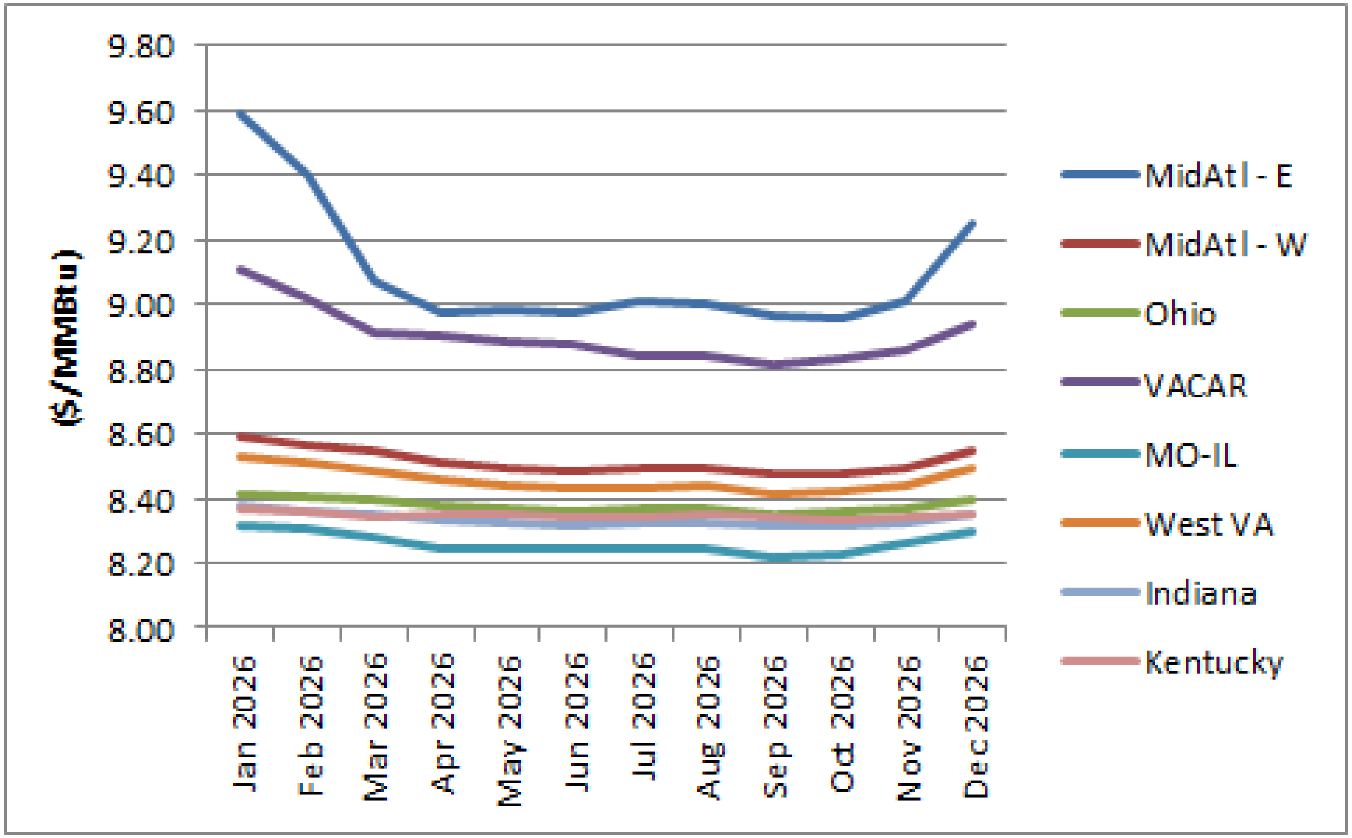
Monthly PJM Natural Gas Prices - Nominal Dollars

- EIA Annual Energy Outlook 2012 Report Henry Hub ($8.02/MMBtu)
- Basis Differentials provided by PJM from Ventyx



Coal Prices

- EIA Annual Energy Outlook 2012 Report
  - 2026 average US delivered price is $3.51/MMBtu (nominal)
  - Blended plant prices develop from Ventyx average historic coal usage (2009 – 2011)

Coal Region	2026 Price ($/MMBtu)
Central Appalachia	4.79
Central Interior	2.54
Gulf Lignite	6.08
Illinois Basin	2.12
Indonesia	2.20
Lignite	4.32
Northern Appalachia	1.55
Powder River Basin	3.31
Rocky Mountain	4.05
Southern Appalachia	1.15

Oil & Nuclear Prices

Oil
(Energy Velocity NYMEX Forecast)

Date	WTI	Gulf Coast Resid (No. 6 Oil) $/bbl	Gulf Coast LS Diesel (No.2 Distillate Oil) $/bbl	Gulf Coast Resid (No. 6 Oil) $/MMBtu	Gulf Coast LS Diesel (No.2 Distillate Oil) $/MMBtu
1/1/2026	112.52	93.89	130.43	14.93	22.39
2/1/2026	112.48	93.86	130.38	14.93	22.38
3/1/2026	112.43	93.81	130.32	14.92	22.37
4/1/2026	112.74	94.07	130.68	14.96	22.43
5/1/2026	113.65	94.83	131.73	15.08	22.61
6/1/2026	113.58	94.77	131.65	15.07	22.60
7/1/2026	113.51	94.71	131.57	15.06	22.59
8/1/2026	113.43	94.65	131.48	15.05	22.57
9/1/2026	113.34	94.57	131.38	15.04	22.55
10/1/2026	113.66	94.84	131.74	15.08	22.62
11/1/2026	114.54	95.57	132.76	15.20	22.79
12/1/2026	114.53	95.56	132.75	15.20	22.79

Nuclear
(Energy Velocity)

2026 Price ($/MMBtu)
$0.75

Emissions Prices

- Compliance by all plants
  - Emission cost assumed to be $0/ton
- All operating plants will have appropriate control technology

Load Projections

- PJM – Based on PJM's 2011 load forecast report, historical load shapes (2004, 2005, 2006) will be energy scaled to 2026 energy by zone. Methodology discussed in Task 1 report.
- Rest of EI – Based on Ventyx "Historical and Forecast Demand by Zone", aggregated to the MAPS Pool (~NERC sub region) level. Individual control area historical load shapes will then be energy scaled using a pool level scaling factor.

MAPS Pool	Ventyx 2026 Forecasted Energy GWh	2010 Energy GWh	Average Annual Growth Rate
PJM	969,596	810,811	1.1%
MISO	605,177	531,156	0.8%
Southern	305,497	250,284	1.3%
FRCC	279,147	229,783	1.2%
SPP	275,816	236,717	1.0%
VACAR	261,710	226,514	0.9%
Central / TVA	255,532	229,162	0.7%
Delta / Entergy	180,012	156,808	0.9%
NYISO	174,383	163,505	0.4%
ISONE	157,208	128,660	1.3%
IESO	142,080	141,897	0.0%
OVEC	231	495	-4.6%
EI	3,606,390	3,105,792	0.9%

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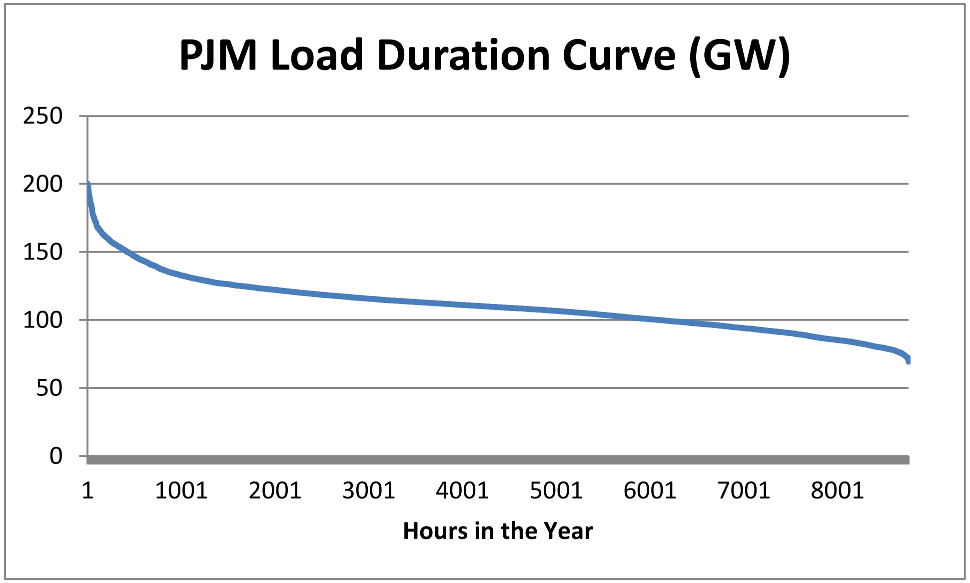
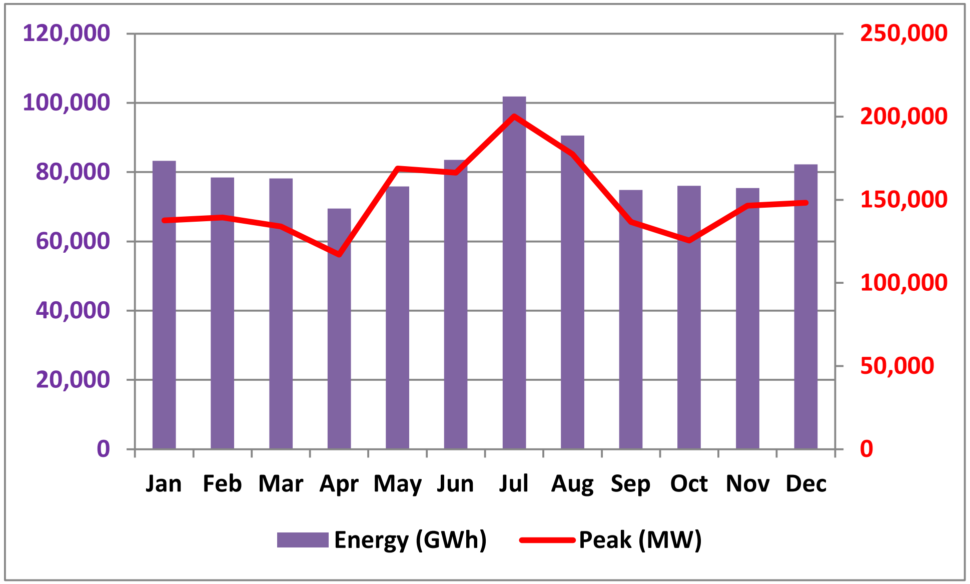
PJM Load


PJM Load Duration Curve (GW)
250
200
150
100
50
0
1
1001
2001
3001
4001
5001
6001
7001
8001
Hours in the Year


120,000
100,000
80,000
60,000
40,000
20,000
0
250,000
200,000
150,000
100,000
50,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Energy (GWh)
Peak (MW)

Thermal Generation Additions

- PJM – queue (with FAC or ISA) plus generics to maintain reserve margin.
- Generic additions were added if base case fell below PJM reserve margin target.
  - PJM Queue had 31.5 GW of FSA/ISA qualified
- Rest of EI – under construction per Ventyx plus generic additions to maintain reserve margins at the GE MAPS pool level.
- Generic additions were split between SCGTs and CCGTs depending on regional needs.
- Existing wind were given 13% capacity credit in the base case; there were very little solar to have any significant impact, and for those, the values used by PJM at the time were applied.

Thermal Generator Parameters

- Start Cost – Based on GE engineering; by size, by type
- Economic Max/Min – Set to operating min/max
- Ramp Rate – Only applied in production cost simulation when looking at spinning reserve capability
- Min Down Time – Based on CEMS data analysis; by type, by size
- Min Run Time – not currently specified
- Heat Rates – GE review of multiple sources including CEMS
- Emissions/Effluent Removal Rates – Net emission rates based on CEMS data analysis from Ventyx
- OM Cost – Ventyx

Generator Retirements

- PJM – Coal plant retirement forecast provided by PJM, Other types announced from Ventyx
- Rest of EI - Announced from Ventyx
- Assume all nuclear plants continue to operate

Hurdle Rates

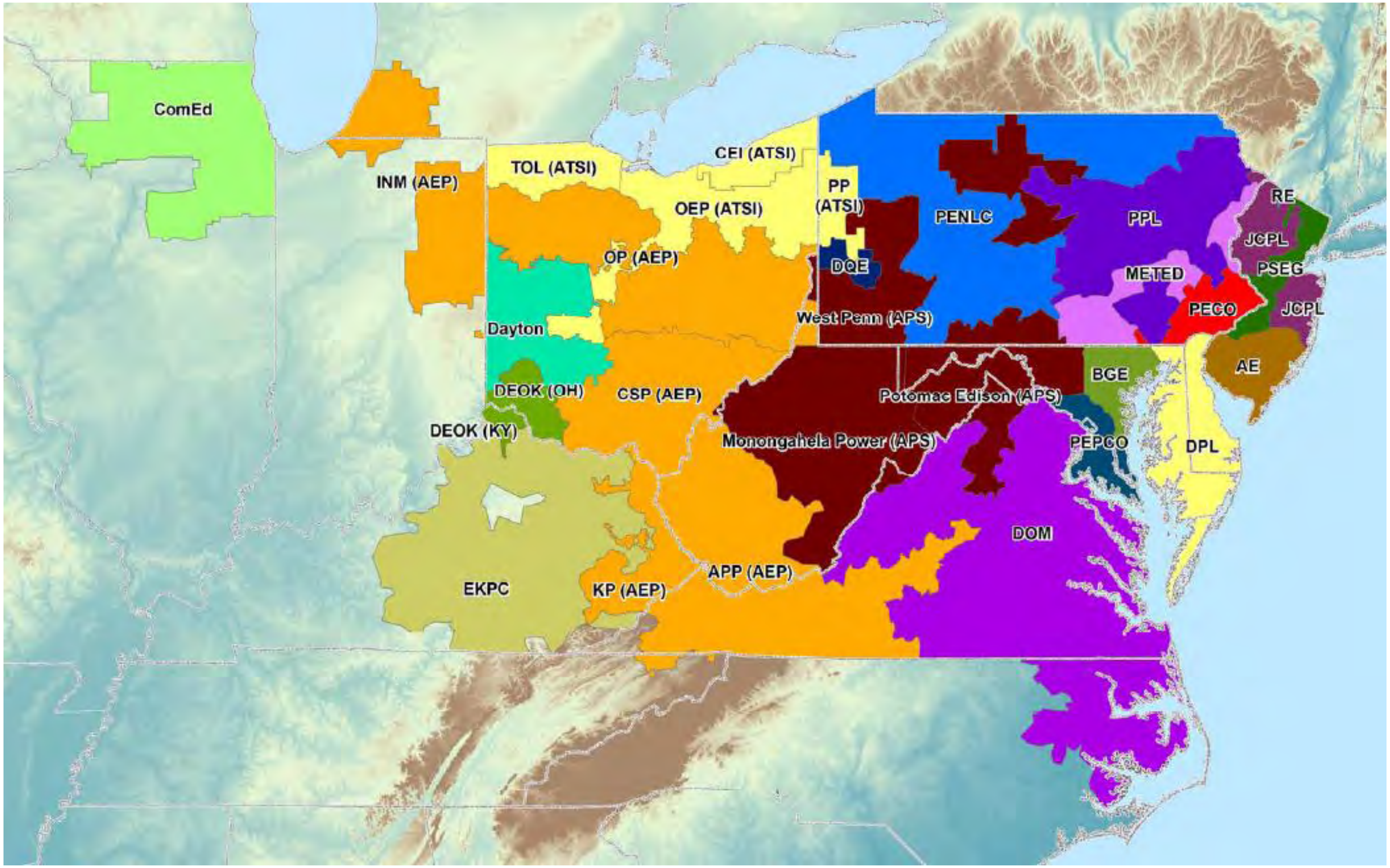
Based on Eastern Interconnect Planning Collaborative (EIPC) study

From	To	Total Hurdle 2010$/MWh
PJM	MIS	
MISO	PJ	
PJM	NY	
NY	PJ	
PJM	Nor Mid	
PJM	TV	
PJM	VA	
VACAR	PJ	
TVA	PJ	

From	To	Total Hurdle 2010 $/MWh
PJM	MISO	2
MISO	PJM	2
PJM	NY	6
NY	PJM	8
PJM	Non RTO Midwest	6
PJM	TVA	6
PJM	VACAR	6
VCAR	PJM	7
TVA	PJM	9

Source:
Future 1 Modeling Assumptions
http://www.eipconline.com/uploads/Future_1_Modeling_Assumptions_Master_9-24-11.xls

PJM Load Zone Geographical Representation January 2013



Source: PJM Load Forecast Report, January 2013

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